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REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

Final Report
June 14, 1995-March 13, 2001

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University of Utah
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Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology in a Low Dip Slope and Basin Reservoir in the Midway-Sunset Field, San Joaquin Basin, California

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Abstract

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

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A previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the upper Miocene Monarch Sand. However, the sand has a shallow dip (about 10°), thus inhibiting gravity drainage, lacks laterally continuous steam barriers within the pay interval, and has a thick water-saturated transition zone above the oil-water contact. These factors have required an innovative approach to steam flood production design that balances optimal total oil production against economically viable production rates and performance factors, such as OSR and OWR. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining recovery of heavy oils throughout the region.

In January 1997, the project entered its second and main phase with the purpose of demonstrating whether steam flood can be an effective mode of production of the heavy, viscous oils from the Monarch Sand reservoir. A steam flood pilot consisting of four 2 acre nine-spot patterns was developed in the center of the property and put on line. During 1998, ARCO Western Energy drilled 37 additional wells on the property outside of the steam flood pilot and began producing them by cyclic steam injection. In January 2000, the new operator of the property, Aera Energy LLC, converted all 37 cyclic wells into ten additional nine-spot steam flood patterns that flank the original DOE pilot on the south, west and north. To convert from cyclic to steam flood Aera Energy LLC drilled 10 additional injectors and three additional temperature observation wells on the property. The only portion of the property not now in steam flood is the very southeast corner where the Monarch Sand pay is less than 200 ft thick. The objective of the project is not just to commercially produce oil from the Pru Fee property, but rather to test which operational strategies best optimize total oil recovery at economically acceptable rates of production volumes and costs.

As of March 2001, after 49 months of steam flood production of the four-pattern pilot and 30-35 months of cyclic/steam flood production of the surrounding 10 patterns, the total cumulative production of oil from the Monarch Sand stands at 1,066,192 bbls. More than half (562,366 bbls) of that oil was from the four-pattern Pru Fee steam flood pilot; the remainder was from 10-pattern array formed by wells drilled in 1998. Steam flood design principles developed and demonstrated for this project now have been adopted with dramatic oil recovery improvement in an adjacent lease in the southern Midway-Sunset field.

Executive Summary

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

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A previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand, part of the upper Miocene Belridge Diatomite Member of the Monterey Formation. However, the sand has a shallow dip (about 10°), thus inhibiting gravity drainage, lacks effective steam barriers within the pay interval, and has a thick water-saturated transition zone above the oil-water contact. These factors have required an innovative approach to steam flood production design that balances optimal total oil production against economically viable production rates and performance factors, such as OSR and OWR. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining recovery of heavy oil throughout the region.

The Midway-Sunset field was discovered in 1894, however, it took nearly a decade for commercial production to begin. The original 13 wells drilled on the Pru Fee property in the early 1900's were operated in primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969, when infill drilling and cyclic steaming was initiated by Tenneco Oil & Gas Company. During the half century of primary production nearly 1.8 MMBO was produced from the Pru property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru Fee property was shut down in 1986 as uneconomic. Total secondary recovery from the 40 acre site peaked at about 300 bopd in 1972, but by the time the property was shut-in it had dropped to less than 10 bopd. ARCO Western Energy (AWE) acquired the lease in 1988 along with various producing properties in the Midway-Sunset field. On October 31, 1998 all of the AWE properties in the southern San Joaquin basin, including Pru Fee, were passed through Mobil with simultaneous closing and transfer to Aera Energy LLC, a Shell-Mobil joint-venture company. AWE continued to operate the property on contract to Aera Energy LLC until December 31, 1998, at which time operatorship passed to Aera Energy LLC.

In June 1995, the shut-in Pru Fee property was selected for a DOE Class 3 oil technology demonstration. The work to revitalize the property started in October 1995. Initially, this

resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1. Pru 101 was cored, steam stimulated, then put into production. Several old wells in the center of the property were recompleted and put into cyclic production to evaluate the feasibility of thermal recovery at this marginal site. In January 1997 the project entered its second and principal phase with the purpose of demonstrating in an 8 acre four-pattern pilot whether steam flood can be an effective mode of production of the heavy, viscous oils from marginal, low-dip portions of the Monarch Sand reservoir where conventional cyclic steaming appeared, from prior experience, to be non-commercial.

The early production success of the pilot and the discovery of significant quantities of oil in the Pleistocene Tulare Formation during the preparation of the steam flood pilot lead AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Thirty-seven additional wells in the Monarch Sand surrounding the steam flood pilot were put on line in 1998 and early 1999. By mid-1999 these cyclic wells had reached oil rates in the range 363 to 381 bopd. In just a year, they had already produced an additional 129.7 MBO over and above production from the steam flood pilot. Upon acquiring the property in January 1999, Aera Energy LLC began modifications to the infrastructure at Pru Fee and all adjacent properties that a year later resulted in conversion of all new "300-series" cyclic wells to steam flood patterns.

As of March 2001, after 49 months of steam flood production of the four-pattern pilot and 30-35 months of cyclic/steam flood production of the surrounding 10 "300-series" patterns, the total cumulative production of oil from the Monarch Sand was 1,066,192 bbls. More than half (562,366 bbls) of that oil was from the four-pattern Pru Fee steam flood pilot; the remainder was from 10-pattern array formed by wells drilled in 1998.

Reservoir simulations with geostatistically generated data sets revealed that the initial fluid distribution in the reservoir had the most significant impact on the economics of the steam flood process. The production strategy adopted in the steam flood pilot involved steam injection within the upper third of the oil column, where the oil saturation (So) is greater than 50%, so as to avoid undue loss of heat to water. It was subsequently learned from examination of wells drilled for the "300-series" cyclic to steam flood conversion that the "initial" fluid distributions in the Monarch Sand are highly variable. Optimal production requires a more flexible strategy for completion of the injectors than that adopted for the pilot.

It is highly likely that without the incentives to ARCO Western Energy (AWE) to partner with the DOE Class Program in carrying out this oil technology demonstration, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was known to be a highly marginal property. Yet, in the four and a half years since the initiation of project the total production from this 40 acre shut-in tract has gone from zero to nearly 1,400 bopd. In addition, the two operators, AWE and Aera Energy LLC, have invested, *without* a DOE matching contribution, in a total of 54 new producers external to the steam flood pilot, 10 new injectors increasing the number of steam flood patterns from 4 to 14, three additional temperature observation wells, and the steam generation/distribution infrastructure to support the expanded operations. Total production from just the Monarch Sand reservoir at the Pre Fee property from the end of 1995 through March 2001 is 1,066.1 MBO.

Aera Energy LLC, observing the manner in which the injectors in the four-pattern Pru Fee pilot were completed, adopted the concept of a large stand-off from the OWC in injector workovers in the "low dip" portion of the Kendon lease immediately west of Pru Fee. The new perforations were placed in the uppermost one-third to one-half of the Monarch Sand, well above the OWC and the Sw transition zone, and deeper existing perforations sealed. It is reported that response from the injector workover using the recommended standoff from the OWC has been outstanding. Increases in oil rates in the renovated patterns average 25 bopd per well with a total increase being over 900 bopd. The OSR increased from 0.20 to 0.35 and the water cut improved.

In order to keep the petroleum industry well informed about the progress and technical success of this project members of the project team have pursued a program of proactive technology transfer. This has included issuing updates on the project in publications likely to be read by thermal recovery operators. Also there have been numerous presentations, many invited, at research conferences, technical meetings and professional conventions. These gatherings have been sponsored by the Petroleum Technology Transfer Council (PTTC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE). We even accepted an invitation to describe the project at an AAPG-AMGP international research conference on mature field development in Veracruz, Mexico. Normally there were several such professional presentations each year of the project. In addition, the team has responded to requests by individual operators for reports and in-house presentations.

Acknowledgements

The project team members wish to acknowledge the helpful advice of Gary D. Walker and Viola Rawn-Schatzinger of the DOE National Petroleum Technology Office on both administrative and technical issues related to the project.

This project has benefited immeasurably from the many contributions of past and current project team members. Although not necessarily authors this final report, their efforts have advanced the goals of the project. The team members are:

Milind D. Deo and Craig Forster: *Petroleum Research Center, University of Utah*

K.M. Deets, Grahem Buksh, C.L. Mongold and L. S. Bultmann: *Aera Energy LLC*

Doug Sprinkel and Roger Bon: *Utah Geological Survey*

Bob Swain, Mike Simmons and Kevin Olsen: *ARCO Western Energy*

Creties Jenkins and Ray Wydrinski: *ARCO Exploration and Production Technology*

The project has depended on access to several critical software products, which have been provided to the prime contractor under academic licenses for use at the University of Utah. We are grateful to the companies for their contributions to the project:

GeoGraphix: *GeoGraphix Explorer*, *Prizm* and *ResEv* workstation modules

Biecep Inc.: *Heresim* geostatistical modeling tools

Computer Modeling Group Ltd.: *STARS* thermal reservoir simulator

Chapter 1

Introduction

General Statement

A previously idle portion of the Midway-Sunset field, Aera Energy's Pru Fee property, has been brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steam flood production design that will balance optimal total oil production against economically viable steam-oil ratios and production rates. The methods used in this DOE Class III oil technology demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize properties with declining production of heavy oils throughout the region.

Geologic Setting

The Midway-Sunset field (Fig. 1-1) is the site of the largest thermal enhanced oil recovery operation in the United States. Cyclic, steam flood, hot-water and in situ combustion (fire-flood) technologies are utilized on an ongoing basis within various parts of the field (Lennon, 1990). Indeed, thermal enhanced recovery methods, now standard in all portions of the field since the early 1960's, are responsible for pulling the field out of a steady decline in production (Nilsen et al., 1996). As a consequence of intensive application of thermal enhanced recovery methods, production rates increased four-fold and currently stand are in excess of 159.0 MBOPD (DOGGR, 2001), making Midway-Sunset California's largest oil field and the third largest in North America in terms of daily production. The scale of the operation is impressive. Over 11,300 wells are producing from an area 21,830 ac in size. Cummulative production from the field through 2000 is 2,596 MMBO and 563 BCF of gas. Estimated remaining recoverable reserves are in excess of 860 MMBO. A major goal of this project is to further increase production and extend the life of the field by encouraging investment in portions of the field previously considered economically marginal for geologic or operational reasons.

The Midway-Sunset field lies along the up-turned western margin of southern San Joaquin Basin (Fig. 2-2) where late Miocene basin-center sands encased in organic-rich diatomite of the Monterey Formation lie close to the surface covered by just a thin cover of Pliocene and Pleistocene fluvial-lacustrine mudstones and sands. The upper Miocene sands were emplaced into the basin from the granitic Salina Block immediately west of the strike-slip Sand Andreas fault, probably through point-source fan delta systems. In the Midway-Sunset field the upper Miocene sand reservoirs are "sediment dump" debris flows and proximal turbidites of considerable thickness, but irregular lateral continuity.

Transpressional growth folds forming adjacent to the tectonically active Sand Andreas system guided the basin sands into the synclines on the basin flood, thus creating reservoir "sweet spots" (Fig. 1-3). The Pru Fee property is located immediately south of the Spellacy anticline (Fig. 1-2) in a possible paleo-synclinal trough.

Although true anticlinal traps are common through most of the southern San Joaquin Basin, the oil pools in the Midway-Sunset field generally are related to unconformity or combination traps (Fig. 1-4). These are controlled by nested unconformities on the east-dipping Temblor Range with the top seal being Pleistocene Tulare shales' Pliocene Etchegoin shales, or diatomite mudstone within the upper Monterey Formation itself. The diatomite mudstone encasing the sand bodies serves as both the lateral seals and the source rock. The trap at the Pru Fee property is an unconformity at the base of Etchegoin shales.

DOE Class 3 Oil Technology Demonstration

The very poor performance of the property at the time it was shut-in in 1986 and the marginal thermal recovery from a new cyclic test well drilled and operated in 1985 had convinced the asset managers that Pru Fee no longer had commercial potential. The low-dip of the reservoir (Fig. 1-5) and thin-pay interval (Fig. 1-6) appeared to condemn the property to remaining shut-in. The adjacent Kendon lease was being successfully produced, but there the dips of strata were high and gravity drainage served as an effective mechanism to move steam-heated oils towards the producers. In the low-dip strata at Pru Fee, it was thought that this mechanism would not be effective. However, it was a goal of the DOE Class 3 oil technology demonstration program to urge domestic operators by example to use innovative, cost-effective methods to extend the commercial life of their oil properties. The Pru Fee property, then owned by ARCO Western Energy (AWE), seemed an ideal candidate for a Class 3 project to show how properly managed steam flood might provide sufficient reservoir energy to revive this discarded oil asset. If successful, there were at the time the project began 28 additional shut-in properties in the Midway-Sunset field (Fig. 1-1; Table 1-1), all of which were candidates for renovation.

In June 1995, the shut-in Pru Fee property was selected for a DOE Class 3 oil technology demonstration. The work to revitalize the property started in October 1995. Initially, this resulted in the renovation of old wells and cyclic production facilities at the site and the drilling of two new wells, Pru 101 and TO-1. Pru 101 was cored, steam stimulated, then put into production. Several old wells in the center of the property were recompleted and put into cyclic production to evaluate the feasibility of thermal recovery at this marginal site. In January 1997 the project entered its second and principal phase with the purpose of demonstrating in an 8 acre four-pattern pilot whether steam flood (Burger et al., 1985) can be an effective mode of production of the heavy, viscous oils from marginal, low-dip portions of the Monarch Sand reservoir where conventional cyclic steaming appeared, from prior experience, to be non-commercial.

The early production success of the pilot and the discovery of significant quantities of oil in the Pleistocene Tulare Formation during the preparation of the steam flood pilot lead AWE early in 1998 to expand operations elsewhere in the Pru Fee property. Thirty-seven additional wells in the Monarch Sand surrounding the steam flood pilot were put on line in 1998 and early 1999. The wells initially were put into cyclic production because sufficient steam production to support steam flood was not available and to minimize the investment to AWE in new infrastructure immediately prior to the sale of the property to Aera Energy LLC. By mid-1999 these cyclic wells had reached oil rates in the range 363 to 381 bopd. In just a year, they had already produced an additional 129.7 MBO over and above production from the steam flood pilot. This number does not count the additional oil produced from the 20 new cyclic wells in the Tulare Formation in the southern half of the Pru Fee property that also came on line in 1998-99.

Upon acquiring the property in January 1999, Aera Energy LLC began modifications to the infrastructure at Pru Fee and all adjacent properties that a year later resulted in conversion of all new "300-series" cyclic wells to steam flood patterns. This DOE Class 3 oil technology demonstration was scheduled to end in March 2000, just one year into the cyclic production and before the performance of the "300-series" conversion of cyclic production to steam flood could be evaluated. In order to gain additional insight into optimal operational strategies at this site, the DOE National Office of Petroleum Technology approved a one-year no-cost extension of this project to allow a side-by-side comparison of cyclic and steam flood thermal recovery methods and the subsequent cyclic-steam flood conversion.

As of March 2001, after 49 months of steam flood production of the four-pattern pilot and 30-35 months of cyclic/steam flood production of the surrounding 10 patterns, the total cumulative production of oil from the Monarch Sand stands at 1,066,192 bbls. More than half (562,366 bbls) of that oil was from the four-pattern Pru Fee steam flood pilot; the remainder was from 10-pattern array formed by wells drilled in 1998.

Monarch Sand Reservoir

Heavy oil production at the Pru pilot is from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation (Gregory, 1996). The pay interval is just 1100-1400 ft deep. Like other sand bodies within the Monterey Formation, it is a deep submarine channel or proximal fan deposit encased in diatomaceous mudstone (Link and Hall, 1990; Nilsen, 1996). The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault just 15 miles to the west of the site (Webb, 1981; Ryder and Thomson, 1989). The top of the Monarch Sand, actually a Pliocene/Miocene unconformity, dips at less than 10° to the southwest. The unconformity bevels downward at a very low angle to the northwest across the upper portion of the Monarch Sand body (Schamel, 1999). The net pay zone, which averages 220 ft at Pru, thins to the southeast as the top of the sand dips through the nearly horizontal oil-water contact (OWC). In the southeast half of the Pru property a thin wedge of Belridge Diatomite overlies the

Monarch Sand beneath the Pliocene/Miocene unconformity providing a somewhat more effective steam barrier than the Pliocene Etchegoin Formation, a silty, sandy mudstone. However, it is the overlying Etchegoin Formation that forms the essential unconformity trap for the Monarch Sand reservoir in this part of the Midway-Sunset Field.

Average Monarch Sand reservoir characteristics derived from core and the log model developed for this project (Schamel et al., 1999) are 31% porosity and 2250 md permeability. The “initial” (1995) average oil saturation was estimated to be 59%. However, all wells have a relatively thick transition zone of downward decreasing oil saturation in the bottom half of the pay interval. The oil is both heavy and viscous, about 13° API gravity and 2070 cp at the initial (1995) reservoir temperature of 100° F. The Pru-101 core reveals a dominance of sand-on-sand contacts with only a few relatively thin intervals of diatomite and silt. The wire-line logs in wells penetrating up to 350 ft of the reservoir also suggest that the Monarch Sand at this site is essentially a single sand body with interspersed remnants of diatomite beds, rather than thin stacked sand bodies encased in diatomite.

Reservoir simulations with geostatistically generated data sets (Schamel, 1999) revealed that the initial fluid distribution in the reservoir had the most significant impact on the economics of the steam flood process. The initial fluid distribution was determined by the placement of the oil-water contact and the resulting transition zone in the reservoir. The production strategy adopted in the steam flood pilot involved steam injection within the upper third of the oil column, where the oil saturation (So) is greater than 50%, so as to avoid undue loss of heat to water. It was subsequently learned from examination of wells drilled for the "300-series" cyclic to steam flood conversion that the "initial" fluid distributions in the Monarch Sand are highly variable. Optimal production requires a flexible strategy for completion of the injectors than that targets steam towards the oil-rich portions the reservoir, where ever that may be.

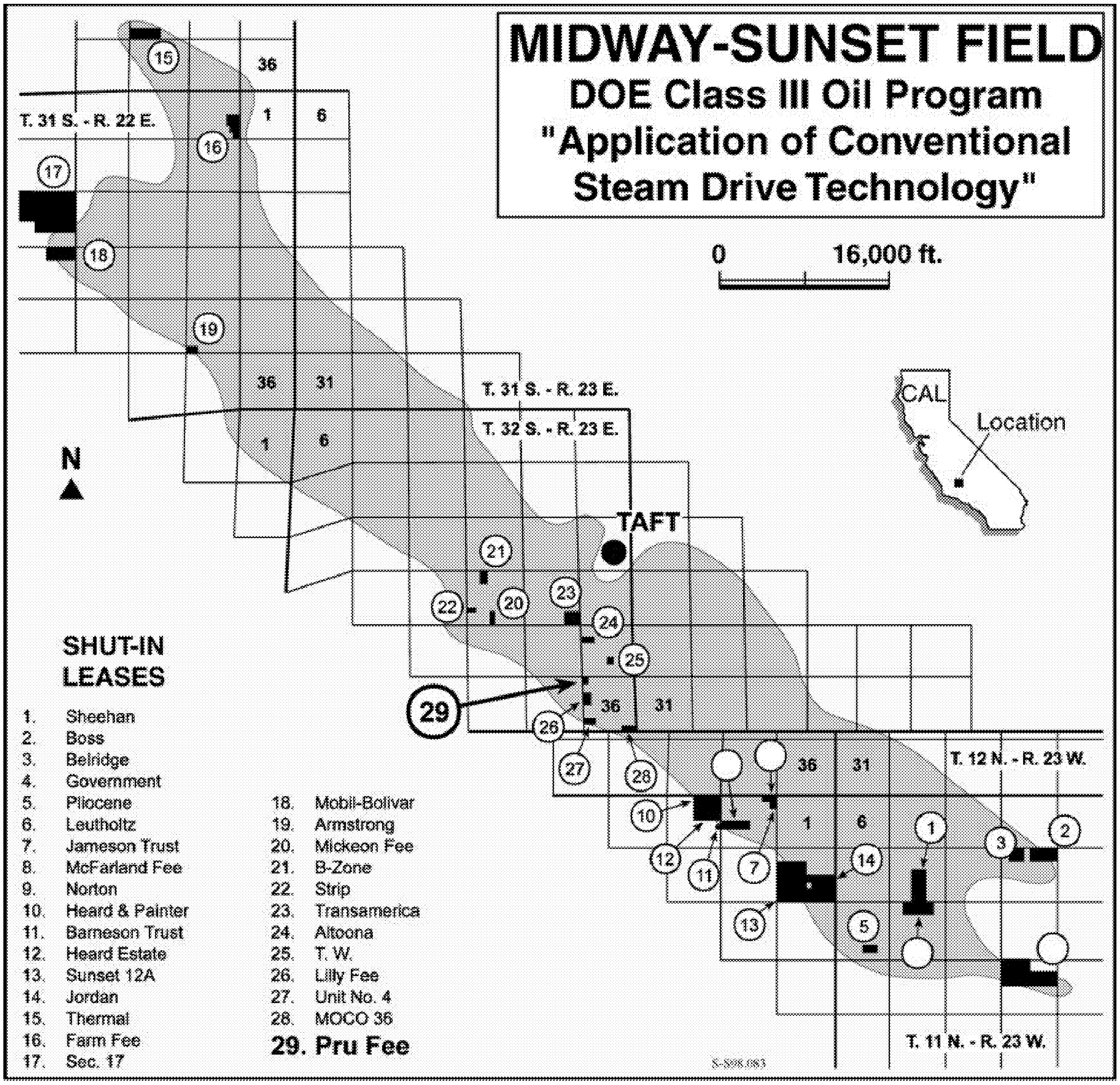

Figure 1-1: Map of the Midway-Sunset field showing location of the Pru Fee property and other leases shut-in at the start of the project.

Table 1-1
Shut-in leases in the Midway-Sunset field in 1995 prior to the Class 3 project

No.	SEC	RGE	TWP	LEASE	OPERATOR	ACRES	BLM
1	8	11N	23W	SHEEHAN	CENTRAL LEASE	80	Y
2	10	11N	23W	BOSS	UNOCAL	80	Y
3	10	11N	23W	BELRIDGE	CHEVRON	40	N
4	17	11N	23W	GOVERNMENT	TEXACO	80	Y
5	18	11N	23W	PLIOCENE	TEXACO	20	N
6	22	11N	23W	LEUTHOLTZ	TEXACO	240	N
7	2	11N	24W	JAMESON TRUST	McFARLAND	10	N
8	2	11N	24W	McFARLAND FEE	McFARLAND	20	N
9	2	11N	24W	NORTON	SHELL	40	N
10	3	11N	24W	HEARD & PAINTER	SHELL	118	N
11	3	11N	24W	BARNESON TRUST	SHELL	20	N
12	3	11N	24W	HEARD ESTATE	SHELL	20	N
13	12	11N	24W	SUNSET 12A	MOBIL	320	N
14	12	11N	22E	JORDAN	CHEVRON	80	N
15	27	30S	22E	THERMAL	TEXACO	200	N
16	2	31S	22E	FARM FEE	MOBIL	75	N
17	17	31S	22E	SEC 17	SANTA FE	439	N
18	20	31S	22E	MOBIL-BOLIVAR	MOBIL	80	N
19	26	31S	22E	ARMSTRONG	MOBIL	20	N
20	22	32S	23E	McKEON FEE	SHELL	40	N
21	22	32S	23E	B-ZONE	BERRY	20	N
22	22	32S	23E	STRIP	McFARLAND	2	N
23	23	32S	23E	TRANSAMERICA	CHAPARRAL	40	N
24	25	32S	23E	ALTOONA	CHAPARRAL	30	N
25	25	32S	23E	T.W.	BERRY	10	N
26	36	32S	23E	LILLY FEE	SHELL	30	N
27	36	32S	23E	MOCO 36	MOBIL	20	N
28	36	32S	23E	UNIT No. 4	CHEVRON	20	N
29	36	32S	23E	**PRU FEE**	ARCO	40	N
						2234	

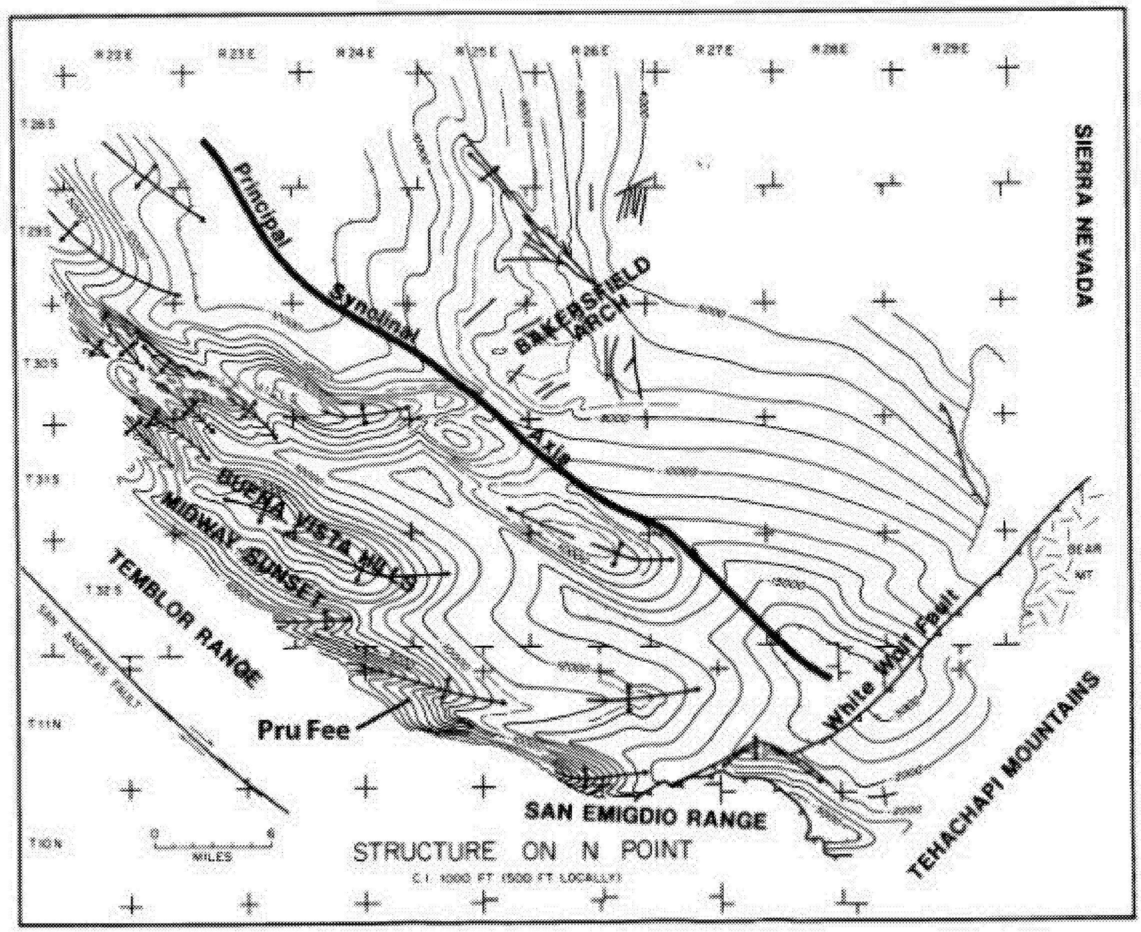

Figure 1-2: Top Monterey Formation structure map showing the position of the Midway-Sunset field along the upturned eastern edge of the Temblor Range. The transpressional anticlines form many of the major oil and gas fields in the southern San Joaquin Basin. In the Midway-Sunset field they combine with nested unconformities to form combination traps, and more significantly in the late Miocane they concentrated thick sand bodies in synclinal troughs, such as that occupied by the Pru Fee asset south of the Spellacy anticline. Modified after Webb (1977

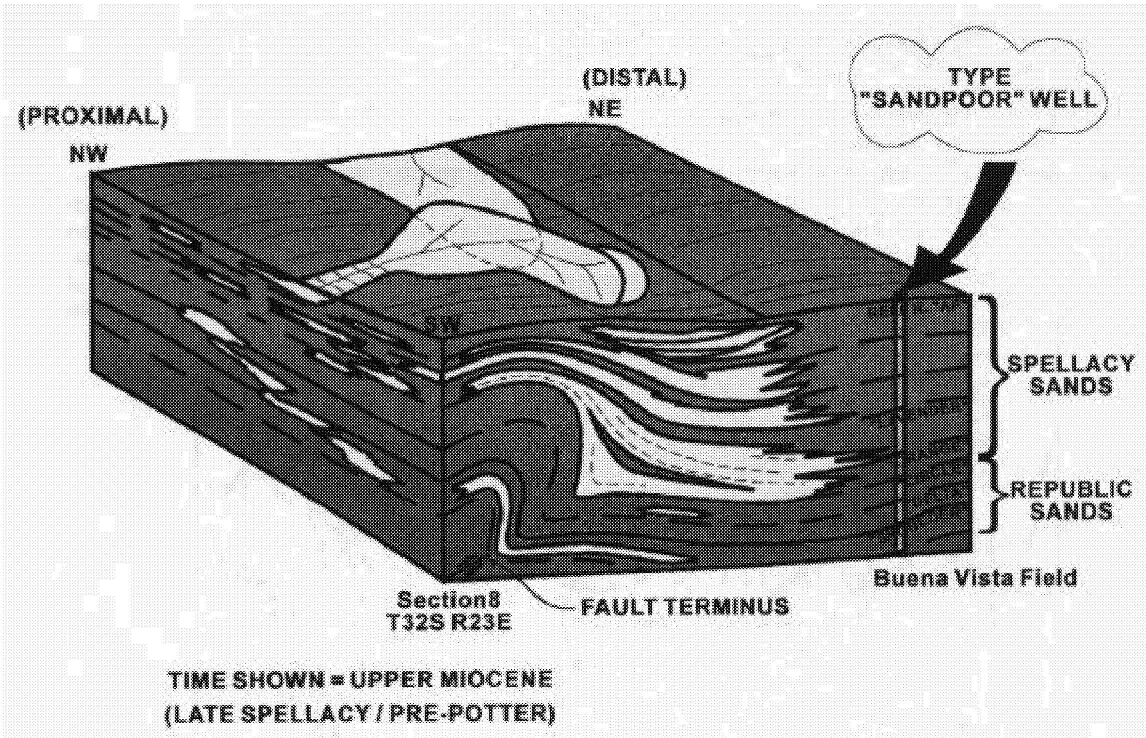

Figure 1-3: Depositional model for upper Miocene sand bodies within structural depressions on the western side of the San Joaquin Basin. The Monarch Sand, the reservoir at Pru Fee, is one of the Spellacy sands. From Gregory (1996).

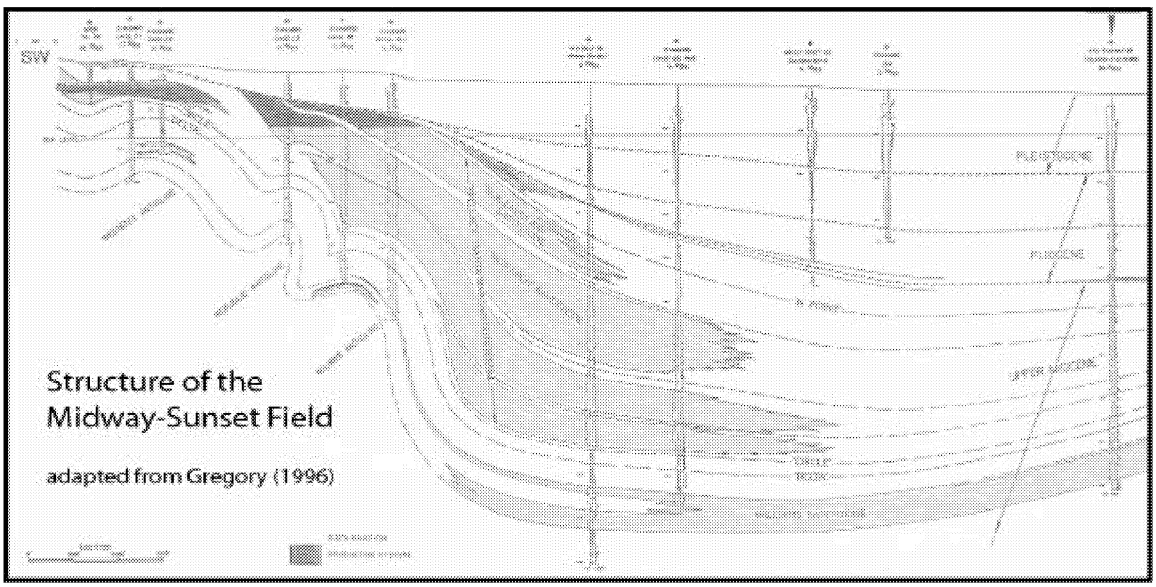

Figure 1-4: Typical cross section through the Midway-Sunset field showing the role of nested unconformities in trapping shallow, heavy oil pools (green) within the upper Miocene Spellacy and older sands (yellow).

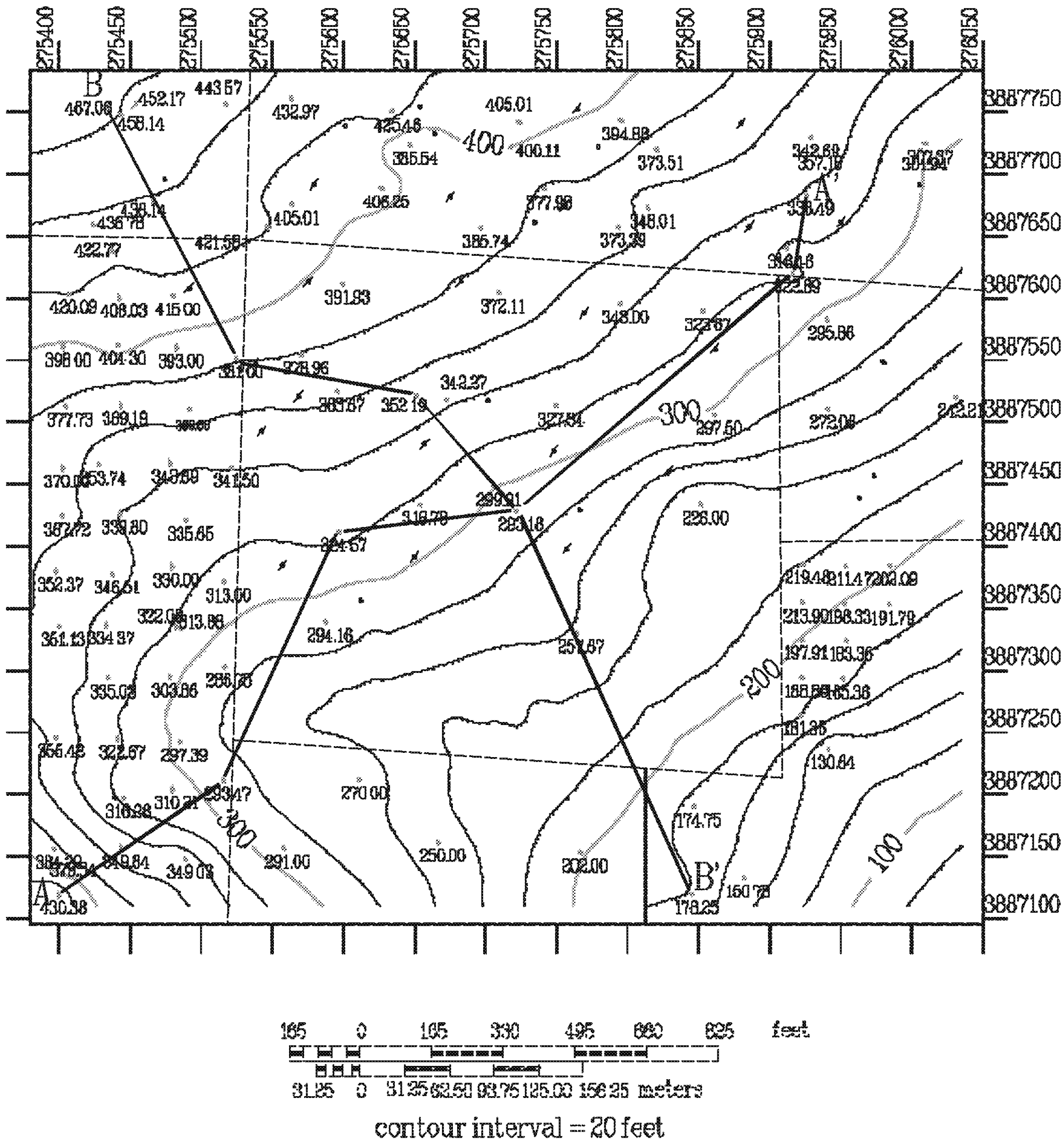

Figure 1-5: Structure of the top of the Monarch Sand reservoir at Pru Fee showing the very low dip, about 10º SE, which is seen as a major impediment to gravity drainage of heated oil towards producers. This is the mechanism responsible for success in the high-dip portions of the Kendon lease southwest of Pru Fee.

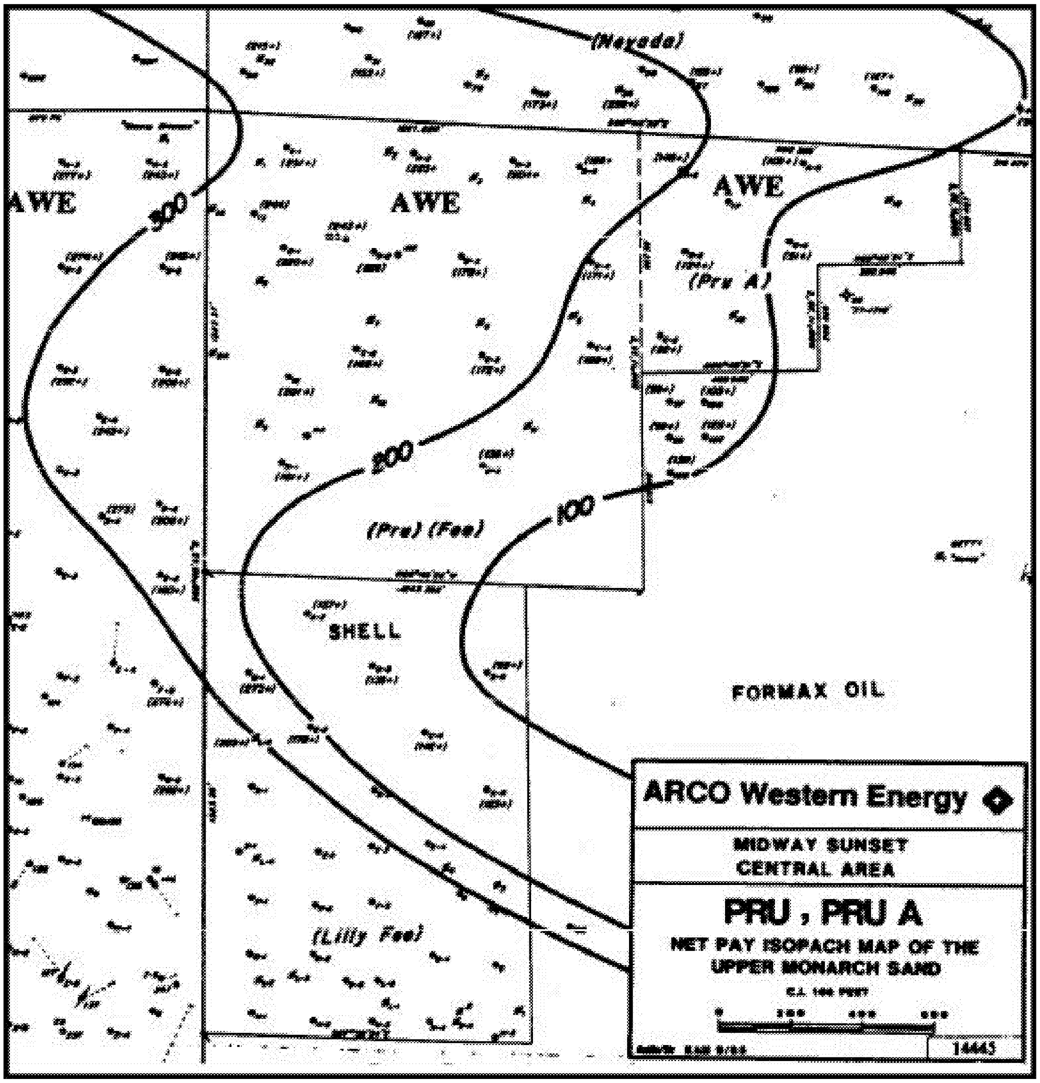

Figure 1-6: Original AWE map of the thickness of the Monarch Sand pay interval prepared before the start of the DOE Class 3 project. The thin pay was considered a serious producibility problem of this asset. However, towards the end of the project the actual thickness of pay was found to be about 80 ft greater than that shown in this map

Chapter 2

History of Oil Production at Pru Fee

Introduction

The Midway-Sunset field was discovered prior to 1880. The original 13 wells drilled on the Pru Fee property in the early 1900's were operated on primary production by Bankline Oil Company prior to 1959, then Signal Oil Company until 1969-1970, when infill drilling and cyclic steaming was initiated by the Tenneco Oil & Gas Company. During the half century of primary production nearly 1.8 MMBO (Table 2-1) was produced from the Pru Fee property, 114 to 151 MBO per well, but production declined steadily reaching insignificant quantities by the late 1960's. Cyclic steaming was partially successful in extracting the remaining viscous 13° API oil until the Pru property was shut down in 1986 as uneconomic. Total secondary recovery from the 40-acre site peaked at about 300 BOPD in 1972, but by the time the property was shut-in it had dropped to less than 10 BOPD. A total of just over 0.6 MMBO was recovered from the Monarch Sand during the less than two decades of initial thermal recovery. ARCO Western Energy (AWE) acquired the property in 1988 along with various producing properties in the Midway-Sunset field.

The very poor performance of the property at the time it was shut-in and the marginal thermal recovery from a new cyclic test well drilled and operated in 1985 had convinced the AWE management that Pru Fee no longer had commercial potential. The low-dip of the reservoir and thin-pay interval appeared to condemn the property to remaining shut-in. However, successful oil production in the adjacent high-dip Kendon lease lead an AWE reservoir engineer, Robert Swain, to draft a steam flood recovery strategy for Pru Fee. Although reviewed annually in the early 1990's by AWE management, the plan for restarting oil production on Pru Fee was never approved. It was this in-house document that served as the basis for the Class 3 proposal submitted by the University of Utah to the DOE in June 1993. An AWE condition for participation in the oil technology demonstration was that the University would take the lead as prime contractor and manage the project. The project's goal was to demonstrate the feasibility of restoring shut-in thermal recovery operations within the super-giant Midway-Sunset field and similar heavy oil properties in California. In early 1994 the project, a collaborative effort by the University, AWE and the Utah Geological Survey, was approved by the DOE. Even as the project got underway in 1995 there was lingering skepticism within AWE management of its ultimate success.

The overall progression of oil production from the Pru Fee property can be summarized in terms of six distinct stages, two preceding this DOE-sponsored oil technology demonstration and four during the project:

Stage 1 (1912-1970): Primary production from 13 wells operated by the Bankline Oil Company and subsequently Signal Oil Comapny.

Stage 2 (1966-1986): Initial thermal recovery from 16 cyclic producers operated by the Tenneco Oil & Gas Company; following the less than two decades of operation the entire Pru Fee property was shut-in.
Stage 3 (1995-1996): The DOE Class 3 oil demonstration project begins with a feasibility study and cyclic testing of refurbished wells.
Stage 4 (1997-present): The DOE Class 3 project continues with a full steam flood demonstration in an 8 acre four-pattern 'pilot' at the center of the property.
Stage 5 (1998-1999): ARCO Western Energy drills 37 new cyclic producers on the property surrounding the existing pilot; production from these wells is monitored as part of the overall oil demonstration project.
Stage 6 (2000-present): Aera Energy LLC converts all of the property to steam flood using the existing AWE cyclic producers and adding on-site steam generating capacity and 10 new injectors.

Table 2-1
Volumes of oil and water produced from the Monarch Sand reservoir, volumes of cyclic or flood steam injected, and performance factors through March 2001. The volumes are separated by stage of development described above.

Stage	Oil (bbls)	Steam-C	Steam-F	Water (bbls)	OSR	OWR
1-Primary	1,789,918			337,703		5.30
2-Initial cyclic thermal	601,544	1,692,466		1,477,889	0.36	0.41
3-Pilot: cyclic	28,975	200,268		183,774	0.14	0.16
4-Pilot: flood	533,391	443,824	1,468,374	2,749,265	0.28	0.19
5-"300-series": cyclic	201,648	795,882		935,941	0.25	0.22
6-"300-series": flood	302,178	422,621	2,236,295	1,096,923	0.11	0.28
Totals =	**3,457,654**	**3,555,061**	**3,704,669**	**6,781,495**		

Total production from the Monarch Sand through March 2001 had reached 3.46 MMBO. The production during the seven decades prior to the start of the Class 3 project was 2.39 MMBO, or 22% of the estimated 10.84 MMBO original oil in place (OOIP). In just over four years of operation since the restoration of thermal recovery at Pru Fee in 1997 an additional 1.07 MMBO has been produced, or 10% of OOIP.

Primary Production on the Pru Fee Property (Stage 1)

The early history of production at Pru (Fig. 2-1) was researched in 1997 by Kevin Olsen using the ARCO Western Energy files. The 13 wells produced by the Bankline Oil Company were distributed rather uniformly across the northern two-thirds of the 40 ac Pru property (Fig. 2-2). Just four wells - Pru-6, Pru-7, Pru-10, and Pru-11 – were located within the area of the current steam flood pilot. Although the net pay within the Monarch Sand reservoir is greatest in the northwest corner of the property and decreases to the southeast, there is no clear correlation between net pay and the cumulative production per well. The cumulative oil and water production by well for the period 1912-1970 is presented in Table 2-2. The oil-water contact rises stratigraphically eastward across the property. Accordingly, the wells on the east and southeast side of the property show higher cumulative water production (Figure 2-3) and lower oil-water ratios (OWR; Table

2-2). This contrast in water production is well illustrated by comparing the production decline curves for Pru-1 (Figure 2-4) in the northwest corner of the property and Pru-11 (Figure 2-5) in the southeast.

Production was entirely primary with a solution gas drive. As a consequence, the total production rate declined gradually during the century, finally in 1970 reaching less than 10 BOPD (Figure 2-1). During the later part of the primary production the rates of water production began to rise, in some wells nearly equaling the rates of oil production. However, this was only in the last decades of primary production. The cumulative oil production (Table 2-2) reached 1,789,918 bbls just prior to the wells being shut in. The average total primary production per well was 137,686 bbls and the range was 114,235 to 151,110 bbls. It is known that gas was produced, but there are no records of the quantity.

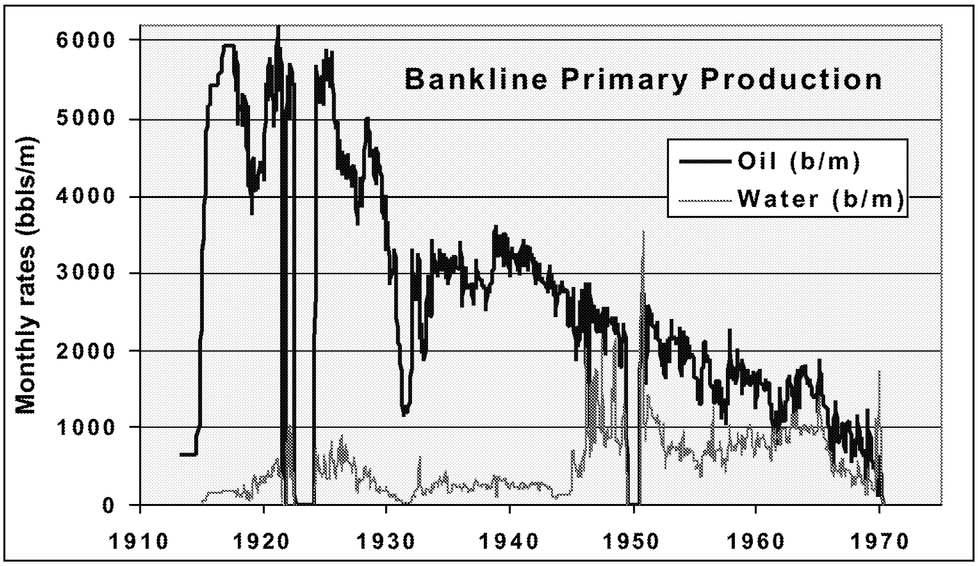

Figure 2-1: Primary production decline in the 13 Bankline wells on the Pru property.

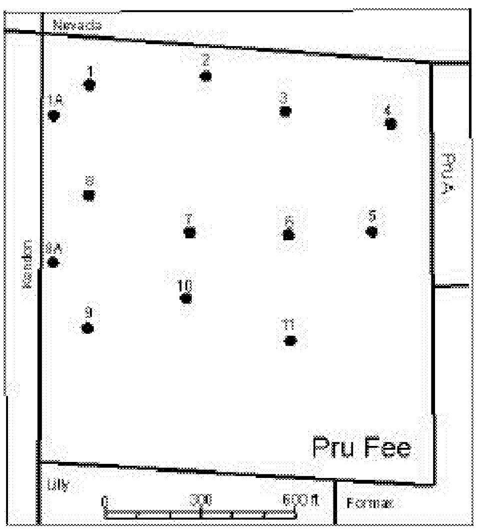

Figure 2-2: Location of the 13 Bankline Oil Company wells on the Pru Fee property.

Table 2-2: Cumulative production, performance factors and dates for the thirteen Bankline Oil Company wells at Pru Fee during the period 1912 through 1970.

Well	Oil (bbls)	Water (bbls)	Water-cut	OWR	Start date	End date
Pru-1	146,539	12,657	0.08	11.58	Dec-12	Apr-70
Pru-1A	114,235	9,290	0.08	12.30	Aug-16	Apr-70
Pru-2	136,181	17,047	0.11	7.99	Oct-14	Dec-69
Pru-3	143,807	42,222	0.23	3.41	Nov-14	Dec-69
Pru-4	142,517	57,706	0.29	2.47	Feb-15	Mar-70
Pru-5	151,110	45,331	0.23	3.33	Mar-15	Apr-70
Pru-6	144,092	22,406	0.13	6.43	May-15	Sep-65
Pru-7	126,683	11,410	0.08	11.10	Jun-15	Oct-65
Pru-8	157,334	8,123	0.05	19.37	Dec-14	Apr-70
Pru-8A	129,123	7,405	0.05	17.44	Oct-16	Apr-70
Pru-9	127,624	9,909	0.07	12.88	Oct-15	Apr-70
Pru-10	145,487	18,960	0.12	7.67	Aug-15	Apr-70
Pru-11	125,186	75,237	0.38	1.66	Jul-15	Apr-70
Total	**1,789,918**	**337,703**				
Avg/well	137,686	25,977	0.15	9.05		

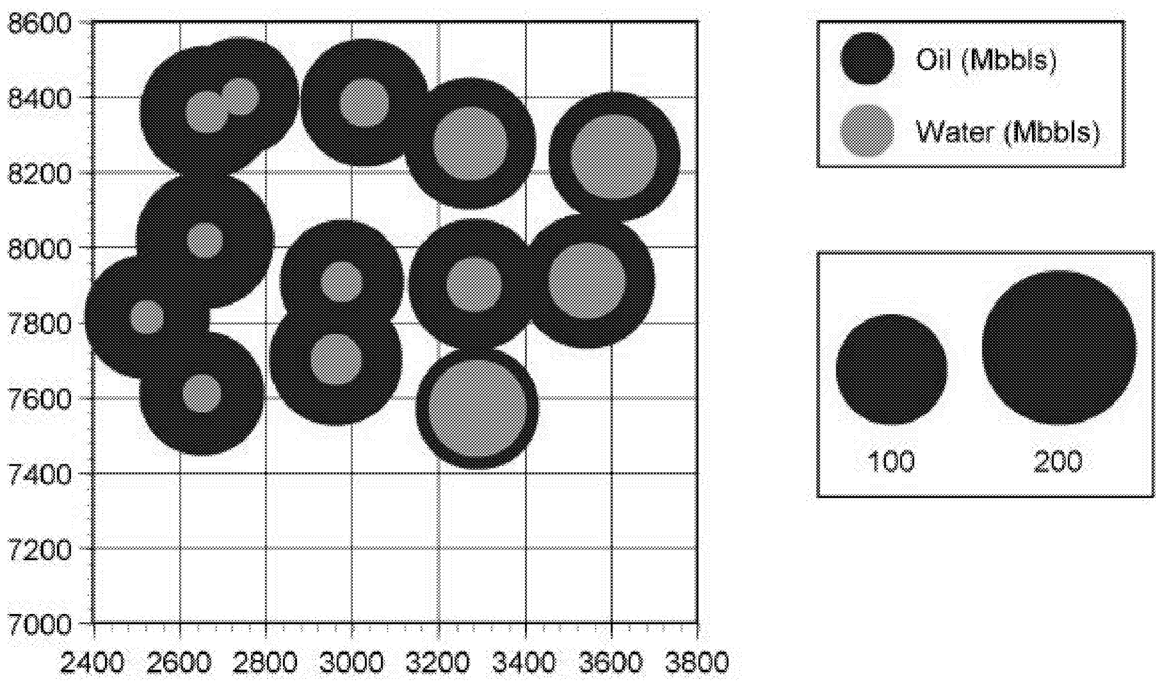

Figure 2-3: Bubble map of cumulative primary oil vs. water production from the thirteen Bankline wells. Note the higher relative water production in the wells on the east and southeast parts of the property. Units are thousands of barrels.

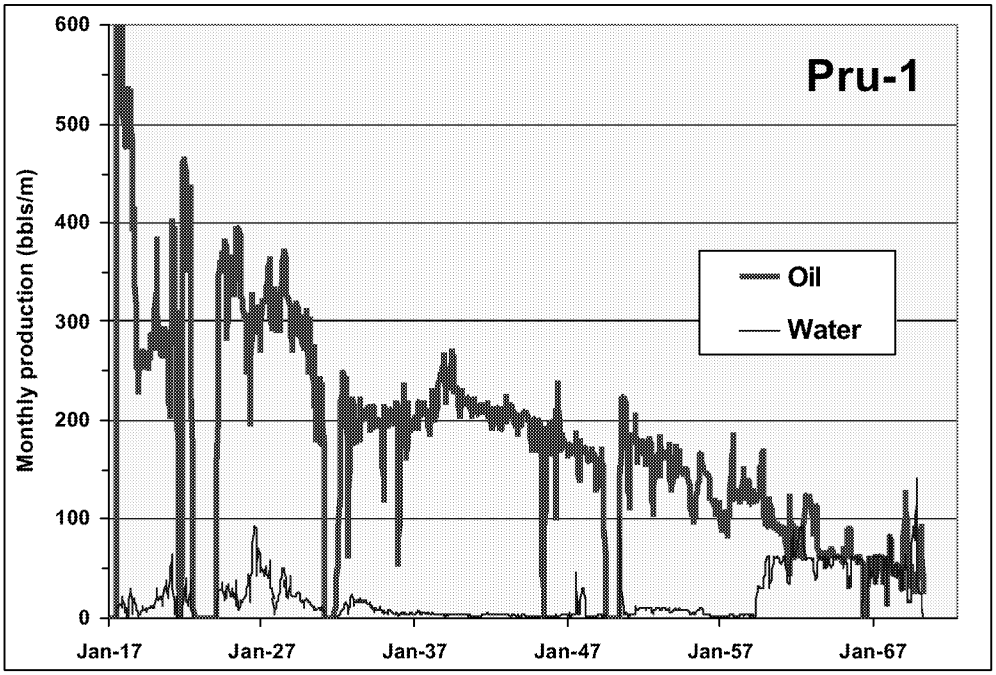

Figure 2-4: Production decline curve for the Pru-1 well in the northwest corner of the Pru Fee property. The water cut over the life of this well is just 0.08. The total production of 146.5 MBO is among the highest of the group.

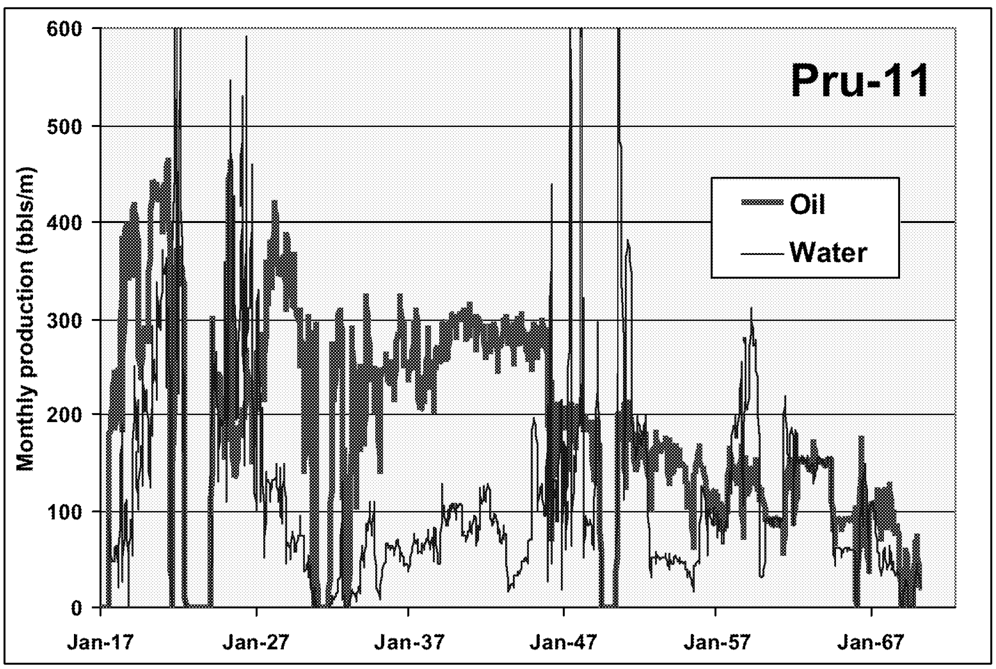

Figure 2-5: Production decline curve for the Pru-11 well in the southeast portion of the Pru Fee property. The water cut over the life of this well is 0.37. The total production of 125.2 MBO is among the lowest of the group.

Initial Thermal Recovery Operations (Stage 2)

Thermal enhanced recovery projects in the Midway-Sunset field began on a small-scale in 1993 and in the Monarch Sand reservoir first in 1995 (DOGGR, 1998). However, it was only in late 1996 and early 1997 that the first cautious efforts at cyclic steam EOR began at the Pru Fee property by the Signal Oil Company. Two new wells, Pru-12 and Pru-13, were positioned along the western side of the property (Figure 2-6), offset from existing primary producers. These wells appear to have been experimental in that Pru-12 was first cycled in December 1966 shortly after completion, but Pru-13 was operated in primary until February 1970. Interestingly, Pru-13 performed better during this period than did the cycled Pru-12 well, 13,983 bbls vs. 9,130 bbls.

Substantial changes in operations followed sale of the property to the Tenneco Oil and Gas in 1969. Between December 1969 and April 1970 all of the original under-performing producers were shut-in and Pru-13 was cycled. In addition, 13 new wells were drilled, completed and put on cyclic EOR between August 1970 and April 1972 (Table 2-3). In general, these new wells were offset from the abandoned primary producers by 100-200 ft, but occupied much the same area of the property. None of the primary producers were cycled.

Table 2-3: Cumulative production and steam injection volumes for 16 wells operated as cyclic steam producers during the period of initial thermal recovery.

Well	Oil (bbls)	Steam (bbls)	Water (bbls)	OSR	OWR	Water cut	Start	Shut-in	#cycles
Pru-12	30,040	57,482	82,558	0.52	0.36	0.73	Oct-66	Mar-85	7
Pru-13	52,402	104,697	92,138	0.50	0.57	0.64	May-67	Oct-85	10
Pru-A1	42,457	85,454	82,958	0.50	0.51	0.66	Aug-70	Feb-86	8
Pru-A2	39,916	115,575	90,019	0.35	0.44	0.69	Dec-70	Aug-84	13
Pru-A3	41,602	107,089	115,165	0.39	0.36	0.73	Aug-70	Aug-84	12
Pru-A4	43,032	94,561	155,606	0.46	0.28	0.78	Oct-71	Apr-85	11
Pru-B1	42,152	107,712	93,078	0.39	0.45	0.69	Sep-70	Jan-86	12
Pru-B2	43,424	109,487	84,859	0.40	0.51	0.66	Jan-70	Apr-84	10
Pru-B3	51,074	122,287	119,404	0.42	0.43	0.70	Oct-71	Apr-85	13
Pru-B4	41,439	105,691	158,061	0.39	0.26	0.79	Oct-71	Apr-85	13
Pru-C2	36,880	79,641	112,151	0.46	0.33	0.75	Oct-71	Feb-86	9
Pru-C3	49,934	129,678	171,238	0.39	0.29	0.77	Jun-70	May-86	15
Pru-C4	36,197	98,935	148,620	0.37	0.24	0.80	Nov-71	Apr-85	13
Pru-D1	22,197	75,691	77,234	0.29	0.29	0.78	Apr-72	Aug-84	8
Pru-D3	27,887	63,260	106,491	0.44	0.26	0.79	Apr-72	Oct-85	5
Pru-533	911	20,649	2,886	0.04	0.32	0.76	Feb-85	Feb-86	2
Totals	**601,544**	**1,477,889**	**1,692,466**	**0.39**	**0.37**	**0.73**			

The group of new cyclic well responded quickly to cyclic steaming reaching maximum project rates in excess of 8000 bopm (270 bopd) within the first year (Figure 2-7). Soon thereafter (1974-75) the rates had dropped to about 4,000 bopm (135 bopd). From that point forward in time there was a very gradual decline in production such that by 1985, the final full year of operation of the wells, production had dropped to 200-300 bopm (7-10 bopd). It is possible that the decline in production was accelerated by the management practices of the wells. In the first years of operation (1971-75) the wells were cycled frequently and with large volumes (20,000-40,000 bspm) of steam, but in all successive years cycling was infrequent and less than 10,000 bspm. Steam treatments ended totally in February 1982. It should be noted, however, that oil rates had fallen off dramatically even while Tenneco was pursuing an aggressive thermal EOR program.

With the new wells alternating between injection of steam and hot water and production of fluids, it is not surprising that the water cuts from the wells would be considerably higher than that of the primary wells. The average water cut for all cyclic wells (Table 2-3) over the less than two decades of production is 0.73, but the range from well to well is considerable, 0.64 to 0.80. This is equivalent to an average OWR of 0.37, and a range of 0.24 to 0.57. As might be expected the largest water cuts (and total water volumes) are associated with wells in the southeastern portion of the property (Figure 2-8).

Over the life of the initial thermal recovery operation 1,477.9 Mbbls of steam was injected to produce 601.5 Mbbls of heavy oil and 1,692.5 Mbbls of water. Total oil production per well varied by just a factor of two (Table 2-3), from a low of 22.2 Mbbls (Pru-D1) to a high of 52.4 Mbbls (Pru-13). There is no systematic spatial variation in total well oil production, as there is for water. The same is true for the OSR, which varies between 0.29 (Pru-D1) and 0.52 (Pru-12). The average OSR of 0.39 is a very favorable, but with increasingly low oil rates of little significance to the economics of the operation. The total volumes of steam injected in each well is depicted in Figure 2-9. A representative set of steam injection and fluid production curves for the life of a single representative well (Pru-12) is shown in Figure 2-10.

For reasons that are not clear, Pru-533 was drilled very close to Pru-B2 in February 1985, cycled twice and then shut-in after only a year in operation. From the standpoint of oil production the well was a technical failure, but it can be argued that the test was far too short. By this time all of the wells on the property were being shut down, a process started in April 1984 and completed in May 1986. In 1988 this Tenneco fee property, together with many others still operating, was sold to ARCO Western Energy.

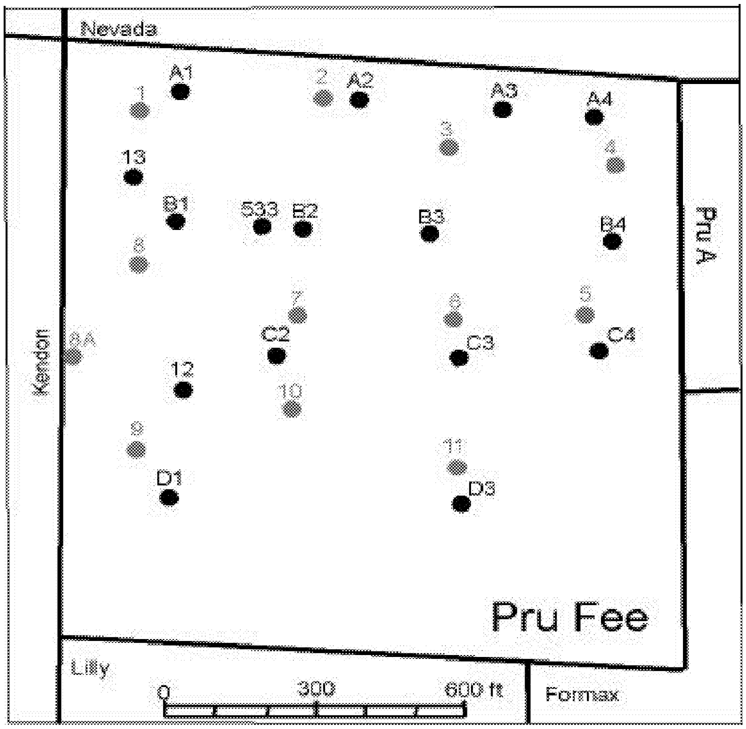

Figure 2-6: Map showing the thermal recovery wells operating during the period 1966-1986. Most of the wells were put on-line between late 1970 and early 1972. The shaded wells are the original primary producers shut-in between December 1969 and April 1970.

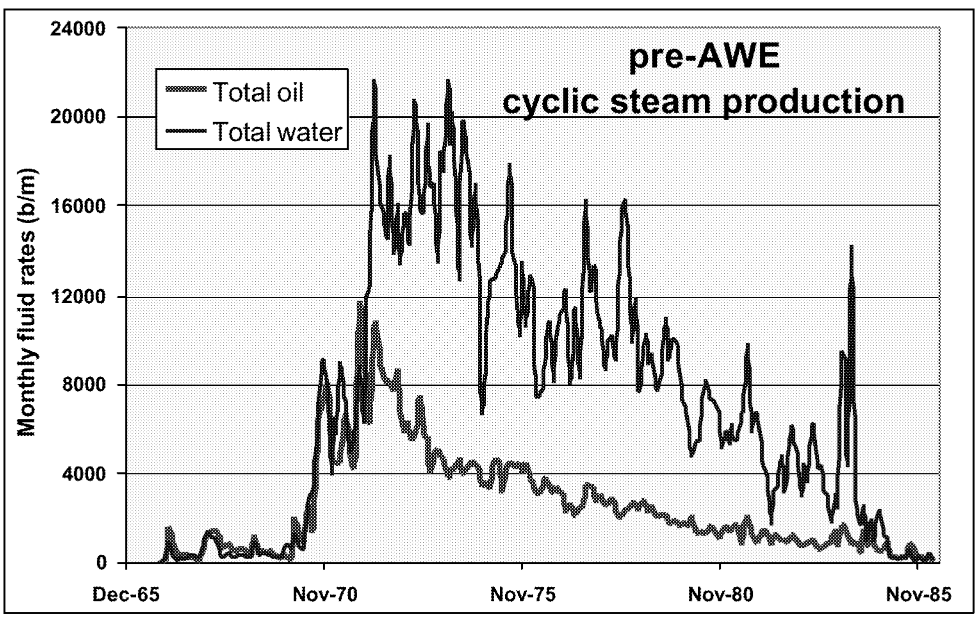

Figure 2-7: Production decline curve for all 16 Tenneco cyclic wells and the large water cuts once steam injection began in earnest in late 1970. The last well was shut-in in May 1996.

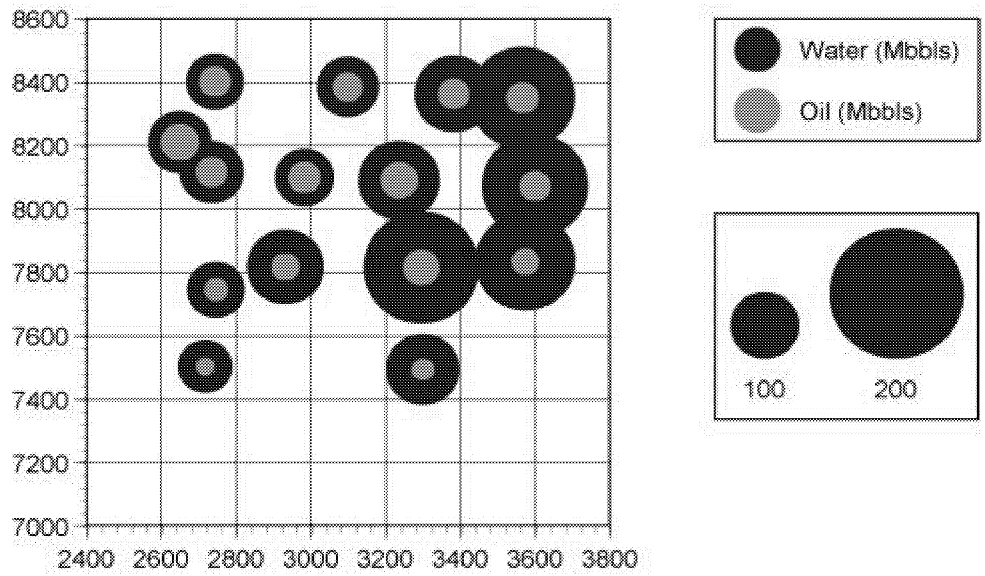

Figure 2-8: Bubble map showing the relative quantities of oil vs. water produced by each of the initial thermal recovery wells operating between 1966 and 1986. The wells in the east and south produced slightly less oil, but considerably more water than those in the northwest part of the property.

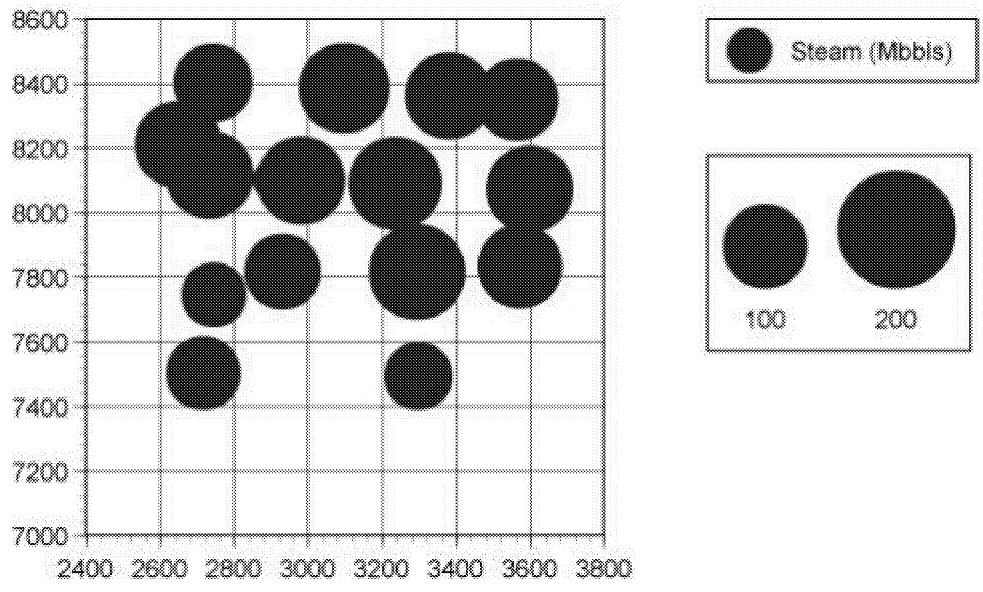

Figure 2-9: Bubble map showing the total quantities of steam injected into each of the 16 initial thermal recovery wells operating in the period 1966-1986. The differences in produced volumes (Figure 2-8) cannot be explained by the differences in steam injected.

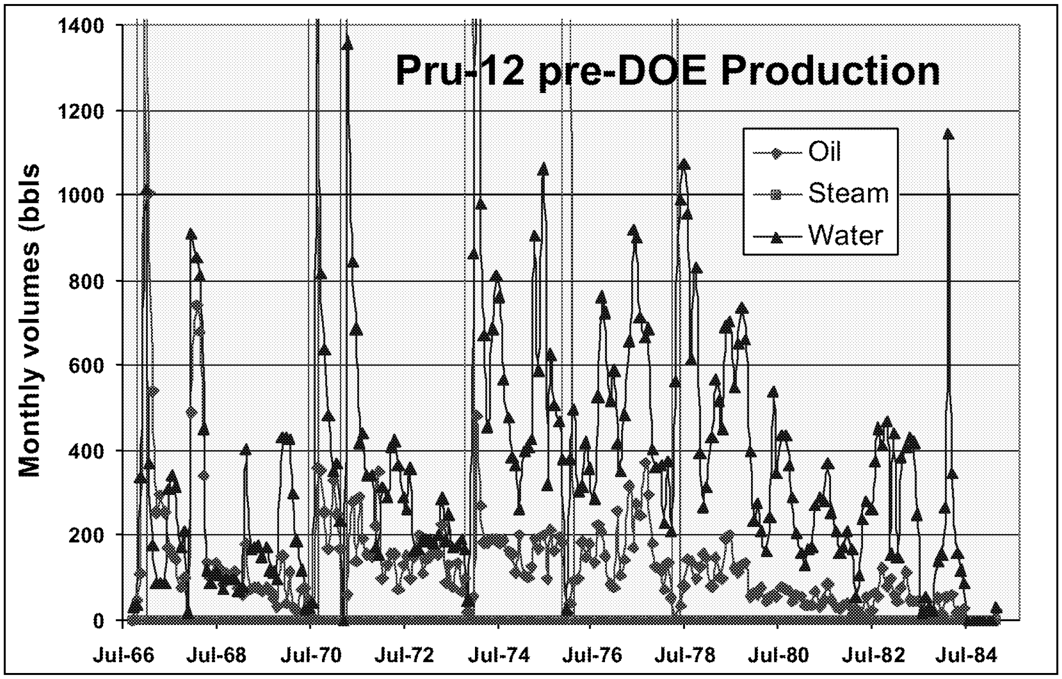

Figure 2-10: Fluids production and steam injection curves for a representative cyclic thermal well, Pru-12, located in the western part of the property. This well was cycled six times between 1966 and 1978, and continued to produce for six additional years without additional steam injection.

DOE-sponsored Oil Demonstration Project

General statement

The DOE-sponsored Class 3 oil demonstration project proceeded in two separate phases. Phase 1 was an 18-month feasibility study to evaluate the technical and economic viability of the proposal to operate the property in steam flood. This study involved parallel activities of a comprehensive reservoir characterization, production simulation and economic modeling investigation together with cyclic steaming baseline tests (Phase 3) of renovated existing and a new well on site. Once the feasibility of the project was demonstrated, an actual field demonstration could occur. Initially, this activity was planned to be a single steam flood pilot (Phase 4) near the center of the property that would have ended early in the year 2000. However, the early success of the pilot lead to AWE drilling many additional cyclic producers (Phase 5) surrounding the pilot, and ultimately to Aera Energy putting the entire property on steam flood (Phase 6). The closing date of the project was extended until March 2001 in order to monitor the results of the additional thermal EOR activities on the property.

Cyclic steam baseline tests (Stage 3)

The Pru property had been operated almost continuously for over 70 years prior to being shut-in in 1986. As a consequence there were many old wells and support facilities in various states of disrepair at the site. In preparation for the Phase 3 cyclic injection and production baseline tests, the site was resurveyed, an existing PLC panel was upgraded with new dynamic surveillance software, many of the flowlines were replaced and the production header was repaired and modified. In addition, a nearby idle freshwater knockout (FWKO) was converted to the Pru wet lact; the old Pru wet lact was converted to a well tester. Provisions were made for produced fluids to go through an existing pipeline to a wet oil metering facility on the adjacent AWE Kendon lease, and then processed through the Kendon tank facility. Clean oil volumes were allocated back to the appropriate properties. Casing vent gases were taken also to the Kendon lease for processing at compressor site K-1.

Eight idle wells on the shut-in Pru Fee demonstration site were inspected, repaired and equipped as injection/production wells to be used in the baseline testing. In addition, a new production well, Pru 101, and a temperature observation well, TO-1, near the center of the demonstration site were planned, permitted and drilled. The wells were completed and equipped in late September, 1995. A core through the Monarch Sand reservoir was removed from the new producer, Pru-101, with over 80% recovery. The location of the wells involved in the cyclic baseline testing are shown in Figure 2-11. By the end of January 1996, all major work for the initial baseline testing on the Pru property was successfully implemented. The site work was carried out under the supervision of Robert Swain of AWE.

The first phase of baseline cyclic steaming began in November 1995 and was continued into early 1996. During the first round, 70,000 barrels of steam was injected into 9 wells near the center of the Pru Fee property. Production peaked at about 90 bbls/day shortly after the close of the first round, but within a period of weeks had dropped back to about 70 bbls/day. Production was dominantly from the new Pru-101 well. The lower than expected flow rates from the refurbished wells is attributed to completion problems that were investigated in subsequent steam cycles. Two of the older wells came back cold immediately after steaming indicating a problem with either steam allocation among the several wells in the test or loss of steam to higher stratigraphic intervals.

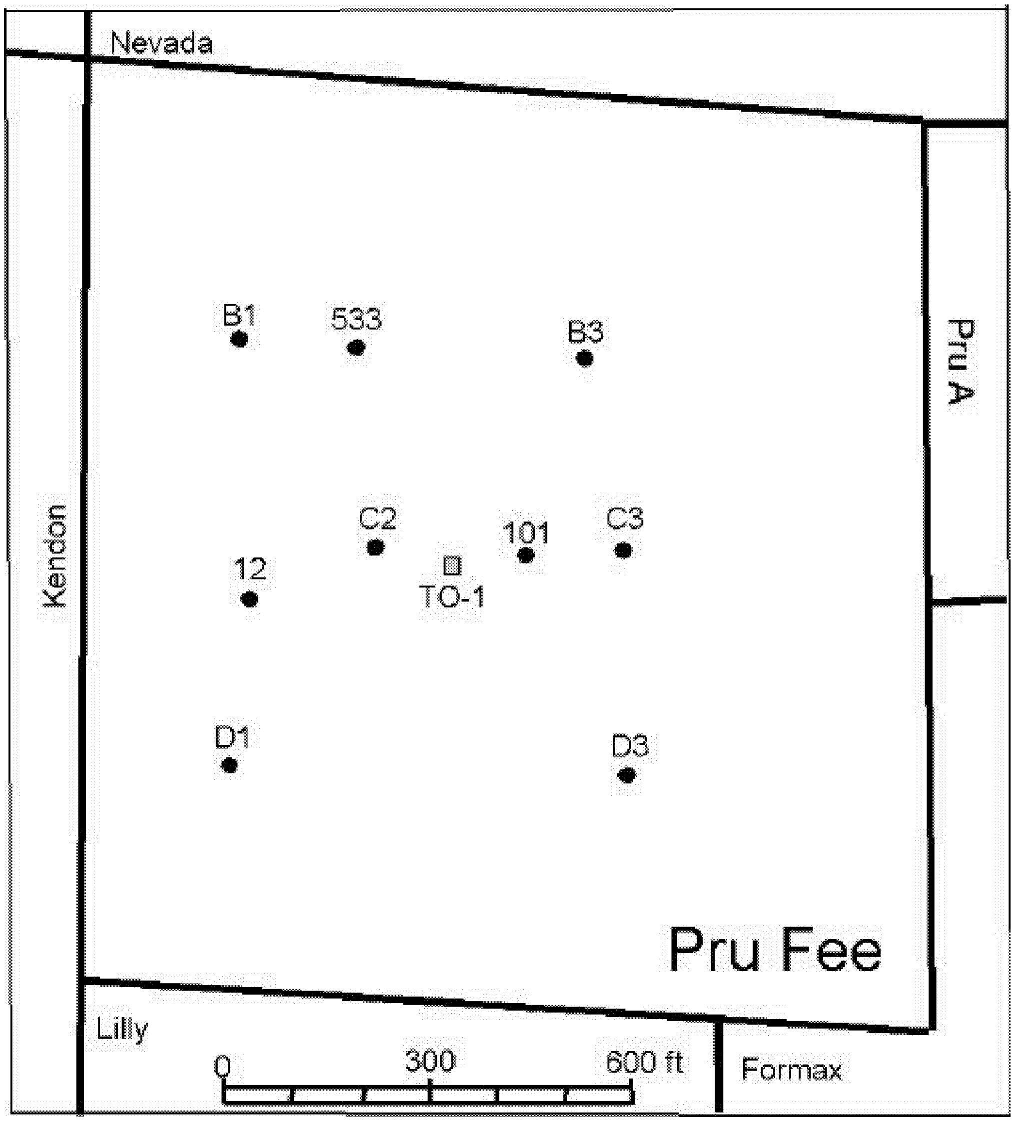

Figure 2-11: Map of the Pru Fee property showing location of the eight refurbished producers, the new Pru-101 producer and the single temperature observation well, TO-1.

The initial steam cycle demonstrated the need to better monitor both the flow of steam to individual wells and the penetration of steam into the reservoir at each well. The second round of steaming was begun in March 1996 under closer monitoring. This involved injecting one well at a time and surveying the formation intervals penetrated using radioactive tracers.

One of the main objectives of Phase 1 was to return the Pru Fee property to economic production and establish a baseline productivity with cyclic steaming. By the end of June 1996, all producers, except well Pru-101, had been cyclic steamed two times. Each steam cycle was approximately 10,000 barrels of steam (BS) per well. No mechanical problems were found in the existing old wellbores.

After the first round of steam cycles it was readily apparent that the new Pru-101 well was producing much better than the old existing Pru wells. In fact, two of the old producers had no response at all to the first steam cycle. There were several possible explanations for the difference in performance, including (a) error in steam measurement and/or allocation, (b) misplacement of steam in the reservoir, and (c) formation damage in the older wells.

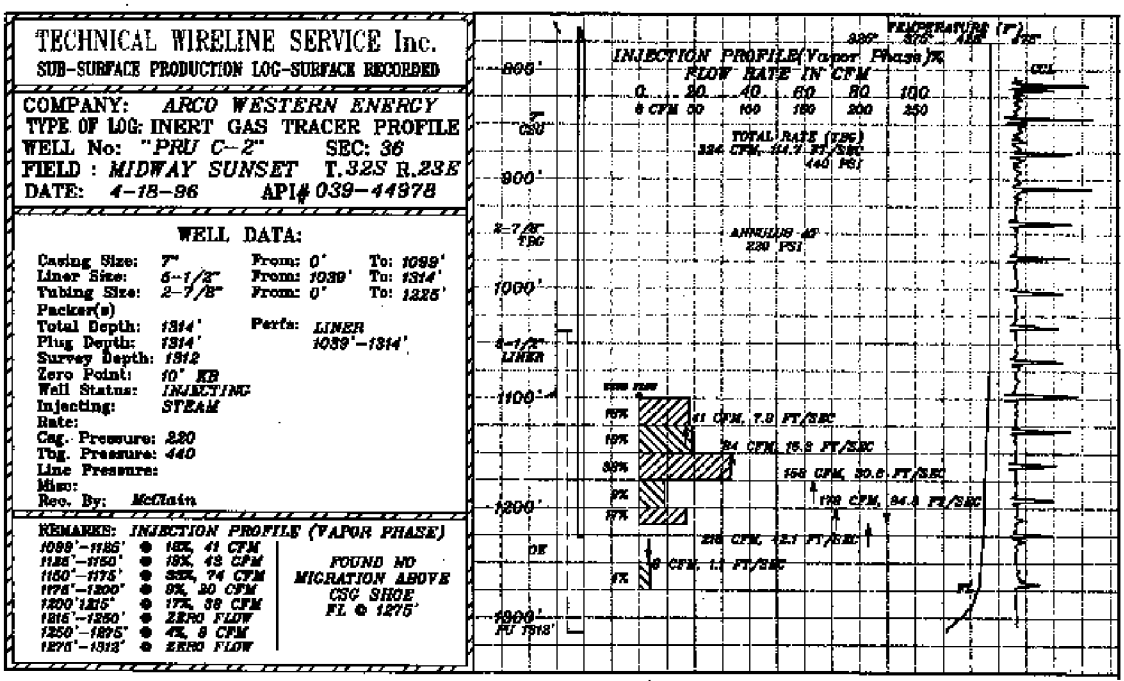

Figure 2-12: *A typical vertical steam entry profile that indicates all of the steam is being confined to the Monarch reservoir with most of the heat distributed above the tubing tail, as expected.*

In each of the second steam cycles, only one well at a time was steamed using a single dedicated steam generator to make sure that the measured volume of steam was accurate. Injection tracer surveys (Fig. 2-12) also were run in each well during the cycle to determine the vertical profile of steam entry into the reservoir. The surveys indicated some variability of vertical profiles from well to well. However, none of the profiles appeared to be particularly unfavorable from the standpoint of heat distribution. There were no obvious small thief zones taking all the steam, leaving the rest of the interval unheated.

These initial attempts to restart production on the property demonstrated convincingly that the reservoir would respond with commercially acceptable per-well oil rates. New producers and start-up of steam flood would only enhance production. The integrated reservoir characterization and production simulation study predicted gross expected reserves at a realistic economic limit for an 8-ac four-pattern pilot alone of 550 MBO. This recoverable reserve estimate was derived from the oil rates simulated for a four-pattern array in the center of the Pru Fee property using a 9-spot, no cycles steam flood base case. This base case used a constant steam rate of 300 bspd per injector (1200 bspd for the entire pilot) over the life of the project. The simulation predicted an initial 10 bopd for new wells, ramping up to 29 bopd (320 bopd for entire pilot) in 16 months. The production would remain relatively flat for 28 months, then start declining harmonically at 40% towards the economic limit.

With a projected $1,900,000 gross capital investment for installing the four-pattern pilot, the project had an estimated PW10 of $1,177,000 and rate of return of 49% based on non-inflated economics. The projected production cost per barrel of oil would be $2.89. Target additional recoverable reserves from the 40 ac property were estimated to be 2.75 MMBO or greater. Considering such favorable project economics, both ARCO Western Energy and the Department of Energy agreed to carry the project forward into the full Class 3 oil technology demonstration phase.

The steam flood pilot (Stage 4)

In January 1997 the project entered its second and main phase with the purpose of demonstrating whether steam flood can be a more effective mode of production of the heavy, viscous oils from the low-dip Monarch Sand reservoir than the more conventional cyclic steaming. The objective was not just to restore production from the pilot site within the Pru Fee property, but to test which production parameters optimize oil recovery at economically acceptable production rates of and costs.

During the period January 19 through April 11, 18 new wells (Table 2-4) were drilled and completed at the 8 ac pilot near the center of the Pru property (Fig. 2-13). Together with Pru-101, which was drilled in 1995 during the evaluation phase of the project, and eight older wells renovated and put on cyclic production at the start of the project, these wells form a four-fold, nine-spot well pattern. The older wells used were B-1, 533, B-3, 12, C-2, C-3, D-1 and D-2. Each injector is surrounded by 8 producers located at the corners and middle edges of a square. Four squares are joined to form a larger square approximately 600 ft by 700 ft, or about 8 ac in size. Along the north edge of the array, a producer is missing from the ideal array between wells 533 and 201. The need to accommodate existing wells into the array has resulted in a departure from an ideal Cartesian spacing of the wells. About half of the producers, those in the interior of the array are in potential communication with two or more injectors. In addition to the 24 wells in the production array, there are four temperature observation wells, each positioned within 80-180 ft of an injector. One of the temperature observation wells, Pru TO-1, was drilled during the initial phase of the project to monitor cyclic steaming in Pru-101.

The injector and temperature observation wells were drilled and completed in a similar fashion. A 6.5 in hole was directionally drilled to about 100 ft below the projected oil-water contact (OWC) and Schlumberger *Platform Express* run in the open hole. A 3.5 in casing was positioned from the surface to the base of the hole (TD), baffled at a depth 32 ft above TD, and cemented in place. The circulation and casing of the wells was done by Halliburton. The casing in the injectors was perforated (Table 2-5) at six locations about 10 ft apart. This 47 to 60 ft interval of perforations was positioned 131 to 202 ft above the OWC and 39 to 47 ft below the top of the Monarch sand. The purpose of the large offset from OWC was to avoid the injection of steam, an expensive commodity, into the low So lower parts of the Monarch Sand reservoir. This thermal recovery strategy is evaluated in Chapter 6.

Drilling and completion of the producers was more complicated. A 9 7/8 in hole was directionally drilled to a depth approximately 100 ft below the projected OWC. Schlumberger *Platform Express* was run in the open hole. A 7.0 in solid casing (23# J-55 LTC) was inserted to a depth about 25 ft below the top of the Monarch Sand, cemented in place and a 7 in wellhead installed. The float and cement at the base of the solid casing was drilled out and the remainder of the open hole through the Monarch Sand to TD was reamed out to a 13.0 in diameter. A 5.5 in liner was inserted inside of the casing to a depth 5 to 50 ft above TD and packed in place with 8 x 12 gravel. Gravel also fills the hole below the hole below the bottom of the liner to TD. The upper section of the liner above the base of the casing and the lower section from 30 ft above the OWC to the lower end is blank. A short segment near the base of the casing is semi-perforated. The remaining section of liner, the longer section through the Monarch Sand, is slotted. Within one or two weeks after release of the rig, tubing, rods and a pump were installed and the well run on production.

Each producer was primed by steaming before putting in full production mode. The target steam volume was 8,000 BS and the target rate 1,000 BSPD. However, the actual steam rates varied from 650 to 1,250 BSPD. Generally, the wells were soaked for 2 weeks after the steam jobs. The priming of the new producers began in March and was completed by the end of May, 1997. By mid-April 1997 all of the producers had been primed and all of the facilities were in place to begin injection within the four-fold, nine-spot array of the Pru pilot. At the end of April injection began with a target rate of 300 barrels of steam per day (bspd) for each of the four injectors. In actuality, the rates have been in the range 250 to 300 bspd. In three of the injectors the initial injection pressure was about 600 psi, dropping gradually over a 6 to 8 week period to a relatively stable 300-350 psi. However, in Pru I2-2, the initial injection pressure of 500 psi dropped very quickly to plateau at 300-350 psi.

The Schlumberger *Platform Express* runs include array induction, SP, temperature, density, neutron density, and gamma ray logs.

In Fall 1995, as the first phase of the project began, eight (8) old production wells were renovated and a new producer, Pru 101, was drilled. After an initial cycle of steaming in the period of October-December 1995, all nine wells were put on production (Fig. 2-15) as the cyclic baseline test. The eight old wells are those now included in the pilot array described above. Initial production, except from Pru 101, was generally poor. The wells were steamed again in February-May 1996, and yet again in July-August 1996. In general, rates improved during this period of repeated stimulation and continued production. During the cyclic test period, production averaged for the total group of nine wells about 70 BOD, ranging from 3 to 10 BOD/well for the old wells and about 15 BOD for Pru 101. The average production rate for the nine cyclic producers through the end of 1996 was about 8 BOD/well. The total production rate had begun to decline in the last months of 1996.

In the period January 11 through April 11, 1997 eleven (11) new producers were drilled. Each was primed by steaming in turn during March-May and immediately put into production. The fluid rates from the 8-acre four-pattern steam flood pilot are shown in Figure 2-15. During the initial phase of evaluation of the project from late 1995 through early 1997, oil rates from mainly renovated cyclic wells averaged 65 BOPD. Soon after the steam flood pilot began in February-March 1997, oil rates rose dramatically reaching a maximum of 424 BOPD in July 1997. The sharp increase in production can, in part, be attributed to the increase in the number of producers from nine to twenty and the fact that

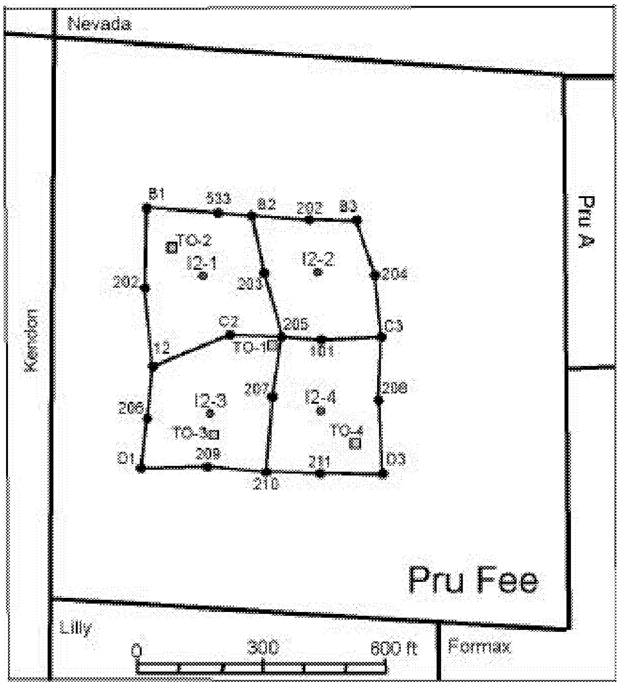

Figure 2-13: Production array for the 8 ac four-pattern pilot steam flood demonstration near the center of the Pru Fee property. The property is a total of 40 ac in size and the array of pilot wells occupies a space approximately 600 ft by 600 ft. Producers are solid black circles, injectors are red-filled circles, and the temperature observation wells are green-filled squares.

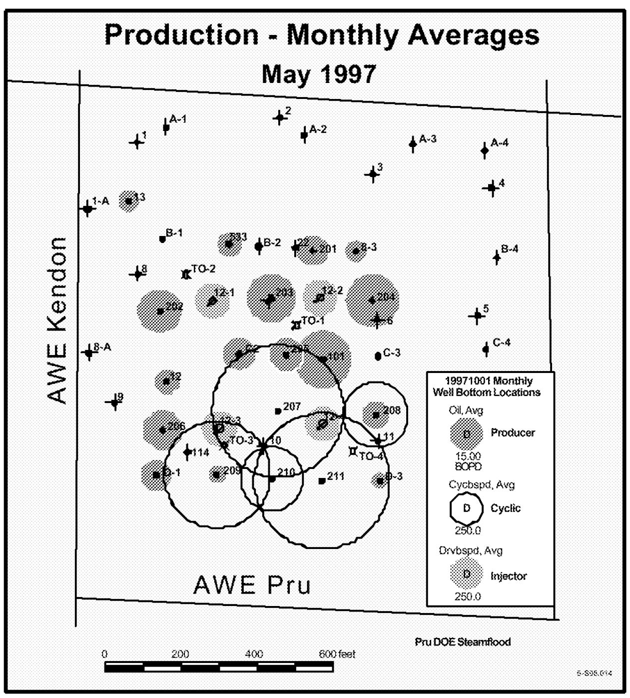

Figure 5.3: Production and injection at the Pru pilot in May 1997.

Table 2-4

MIDWAY-SUNSET FIELD CLASS III OIL TECHNOLOGY DEMONSTRATION PROJECT

ARCO Western Energy Pru Property: Section 36 Township 32S Range 23 E

Wells Drilled for the 8 ac Pilot Demonstration in Center of Property

Well Name	API Serial No.	Spud Date	Prod. Date	TD (ft)	KB (ft)	GL (ft)
Pru 101	04030-04475	9/16/95	10/11/95	1402	1394	1381
Pru 201	04030-07115	1/19/97	2/13/97	1512	1429	1416
Pru 202	04030-07114	1/27/97	4/11/97	1500	1383	1370
Pru 203	04030-07113	2/9/97	2/25/97	1497	1418	1405
Pru 204	04030-07112	2/6/97	2/15/97	1476	1393	1380
Pru 205	04030-07111	2/13/97	3/7/97	1468	1383	1370
Pru 206	04030-07110	2/20/97	3/28/97	1483	1399	1386
Pru 207	04030-07109	3/13/97	3/30/97	1452	1371	1358
Pru 208	04030-07108	2/9/97	3/4/97	1462	1372	1359
Pru 209	04030-07107	2/25/97	3/24/97	1482	1398	1385
Pru210	04030-07106	3/8/97	3/30/97	1400	1380	1367
Pru 211	04030-07105	3/1/97	3/23/97	1415	1355	1342
Pru I 2-1	04030-07151	2/17/97	NA	1471	1383	1370
Pru I 2-2	04030-07152	1/24/97	NA	1486	1393	1380
Pru I 2-3	04030-07153	3/11/97	NA	1464	1381	1368
Pru I 2-4	04030-07154	3/6/97	NA	1441	1359	1346
Pru TO-1	04030-04476	9/14/95	NA	1529	1394	1381
Pru TO-2	04030-07155	1/17/97	NA	1529	1445	1432
Pru TO-3	04030-07156	2/22/97	NA	1485	1398	1385
Pru TO-4	04030-07157	3/4/97	NA	1434	1355	1342

Table 2-5

Depths of Perforations in Injector Wells in the Pilot Demonstrtation

Well Name	Top Monarch	Perforations (ft)						OWC (ft)
Pru I2-1	1057	1104	1116	1123	1134	1142	1160	1355
Pru I2-2	1088	1127	1136	1142	1150	1160	1174	1362
Pru I2-3	1103	1149	1164	1177	1183	1200	1209	1358
Pru I2-4	1106	1150	1163	1178	1185	1198	1206	1331

Note: All well depths are in feet down hole, not TVD.

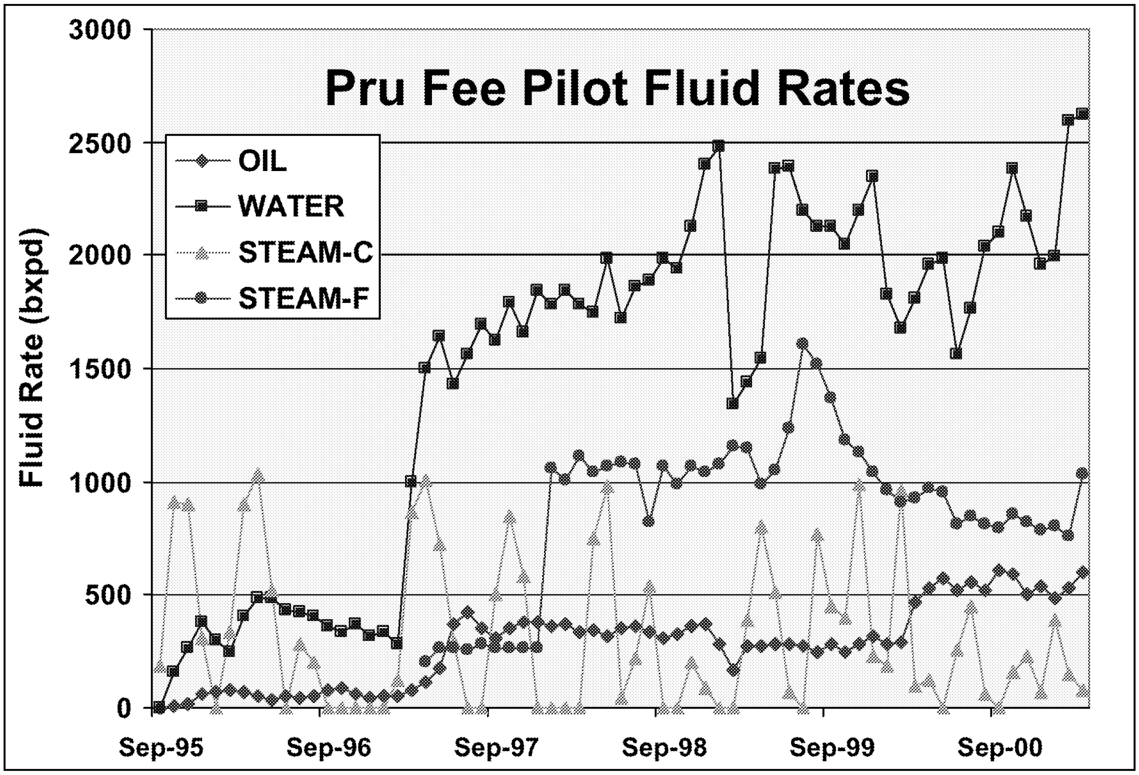

Figure 2-13: Daily rates of fluids produced from and injected in the four-pattern Pru Fee steam flood pilot. Prior to early 1997 a small quantity of oil was produced in the cyclic baseline testing.

the performance of the new wells is consistently better than the old renovated wells (Fig. 2-14). However, the well average jumped from about 8 BOD to nearly 20 BOD with the onset of the pilot steam flood. After the initial spike the oil rates fell off slightly to maintain a general range of 300 to 370 BOPD through the latter half of 1997 and all of 1998. However, production rates fell below 300 BOPD at the time of the transfer of operatorship and for all of 1999 and the first two months of 2000 they were in the general range 250 to 310 BOPD.

The drop in oil rates is a consequence of infrastructure improvements to the site undertaken by Aera Energy LLC. The new construction, in part, brought additional steam to Pru Fee from the adjacent Kendon lease so as to cycle the new "300-series" wells more rapidly and bring up reservoir temperature in the Monarch Sand across the entire property more quickly. During this period, fluids from Pru Fee were being routed to processing facilities on the MOCO property. There they were commingled with fluids from all adjacent leases, then metered. By late February 2000, a new dedicated metering system for the Pru Fee property was operational. Immediately oil rates increased dramatically from 285.6 bopd in February to 444.2 bopd in March. The sharp increase cannot be fully attributed to inaccurate metering during the year prior to March 2000. At least some portion of the increase might be explained by a favorable response of pilot producers to the onset of steam flood in the surrounding "300-series" patterns.

The oil rates continued to rise into the second quarter of 2000 to exceed 500 bopd, a rate sustained through March 2001 during which the average rate was 600 bopd. A slightly higher average oil rate of 610.9 was reached in September 2000. The average per producer oil rate increased from less than 20 bopd prior to March 2000 to about 30 bopd. The higher oil rates were sustained even through a year of unusually low steam injection rates in the pilot patterns (Fig. 2-15).

The steam flood performance factors (Fig. 2-16), the oil-steam (OSR) and oil-water (OWR) ratios, have been favorable through the duration of the steam flood, except in 1999 when the actual produced volumes (Fig. 2-15) may have been under-reported. Both measures of performance have greatly improved since March 2000.

Through March 2001 the four-pattern Pru Fee steam flood pilot had produced a total 533,391 bbls of oil. To produce this volume of oil 1,468,374 bbls of steam was injected into the four injector wells and an additional 443,824 used in cyclic stimulation of the producers. About 30% of the total steam injected was used to stimulate the producers. The OSR for the entire pilot steam flood is 0.28. The volume of water produced from the steam flood pilot is 2,749,265; the OWR is 0.19. The steam flood oil volume is in addition to the 28,975 bbls produced in 1995-96 in the cyclic baseline testing.

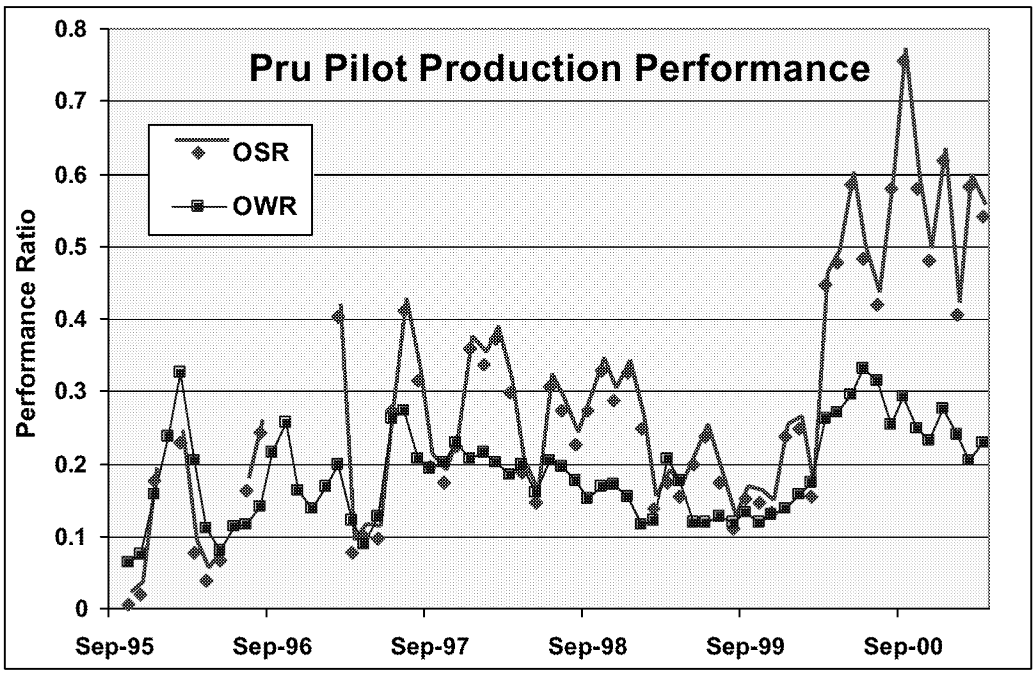

Figure 2-16: Performance ratios for the steam flood pilot through the entire period of the Class 3 project. Note the favorable performance during the initial steam flood period, 1997-98, the degraded performance during 1999, and the very good performance (OSR = 0.4 to0.6) after the entire property is converted to steam flood early in 2000.

Expansion of Production (Stage 5 and 6)

The early production success of the Pru steam flood pilot and the discovery of significant quantities of heavy oil in the Pleistocene Tulare Formation during the preparation of the pilot lead ARCO Western Energy (AWE) early in 1998 to expand operation elsewhere in the Pru Fee property. The 37 "300-series" wells drilled throughout 1998 (Table 2-6) surround the four-pattern steam flood pilot on the south, west, north and northeast (Fig. 2-17). Only the southeast corner of the 40 acre property, where the Monarch Sand pay is considerably less than 200 ft, was not drilled. The wells were drilled, completed, primed and put on line in cyclic mode in three phases: six wells in January, an additional six wells in May, and the remaining 25 wells in the period August through October. By January 1999, when Aera Energy LLC began operating the property, only 28 producers had been primed and were on line (Fig. 2-18). It was not until late spring-early summer that the entire group of "300-series" wells were producing.

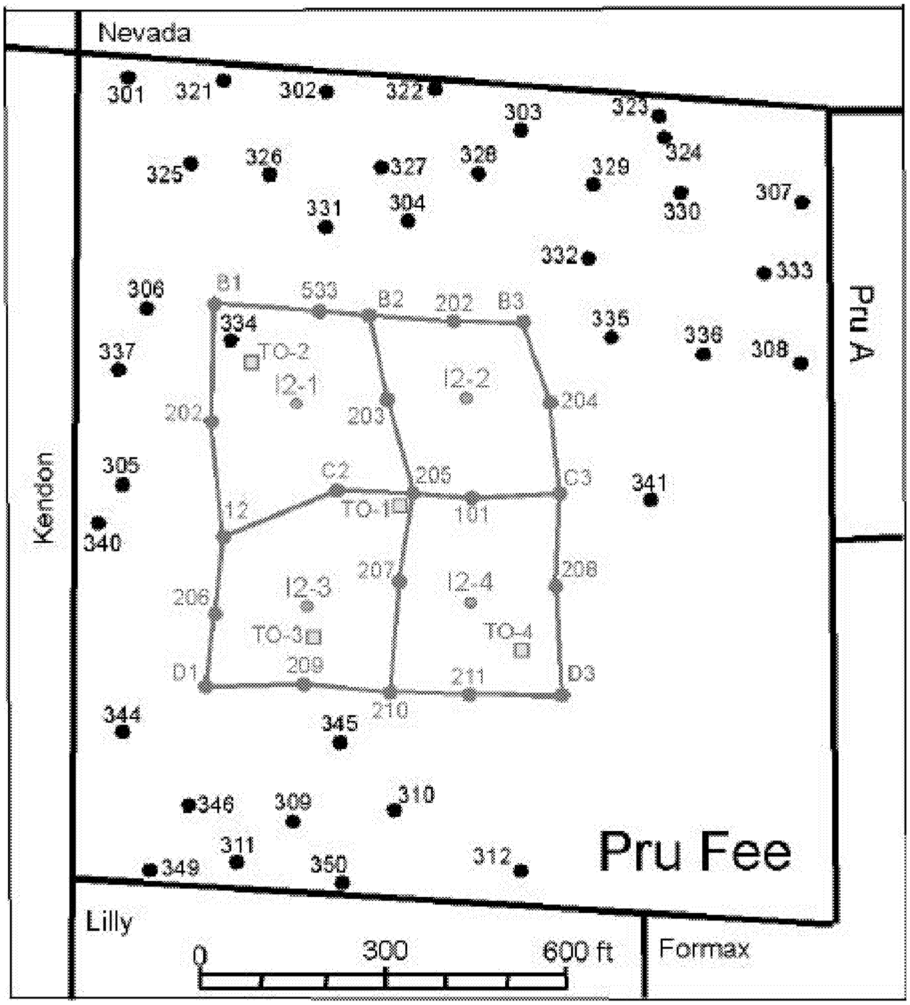

Figure 2-17: Location of the 37 "300- series" wells drilled during 1998. first to support cyclic thermal recovery (Stage 5) and then early in 2000 converted to steam flood arrays (Stage 6).

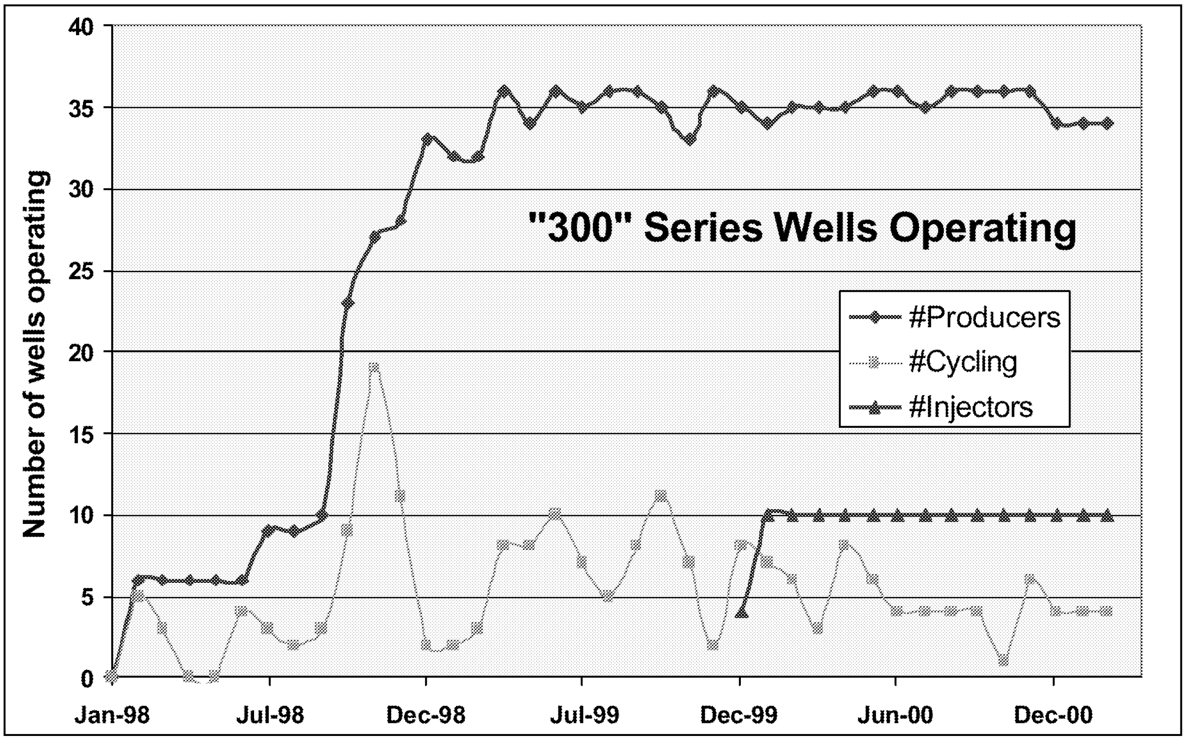

Figure 2-18: Operational history of "300-series" wells being steam cycled or produced in each month since January 1998. The wells were brought into 10 new steam flood patterns (see # injectors) that operated without interruption after January 2000

Initially all of the wells were completed as producers to be cyclic steamed. The wells were drilled and completed by nearly the same procedures as used for the pilot producers, but with one significant difference. To lower the capital cost of the new "300-series" producers the wells were "open-hole" completions. That is, they were not reamed out to a 13 in diameter through the Monarch Sand pay interval and the hole was not gravel packed. The slotted liner was merely inserted into the initial 10 in hole through the Monarch Sand and cemented in place top and bottom. As will be seen, this decision to cut initial operational costs has had substantial impact on the producibility and profitability of the wells.

In addition to the 37 new wells drilled into the Monarch Sandstone, 20 wells were drilled into the heavy oil saturated intervals in the shallower Tulare Formation. These wells are designated "TPxxx". For the most part the wells are clustered in the southwest quadrant of the Pru Fee property, overlapping only the southern edge of the steam flood pilot. Three of the wells, however, are in the southernmost part of the southeast quadrant. The wells have a total depth of about 700 ft and were all completed as cyclic producers. None of the Tulare oil produced from these wells is commingled in the production stream with oil produced from the Monarch Sandstone reservoir.

The total of 37 new wells drilled by AWE on the Pru Fee property in 1998 represented a substantial investment in enhanced production. Already by mid-year 1999, this investment was having a substantial payback.

Table 2-6: Description of the "300" series wells drilled and completed in 1998

Well Name	API Serial No.	Spud Date	Prod. Month	TD (ft)	KB (ft)	GL (ft)	Logged?
Pru 301	04030-10130	1/12/98	Feb-98	1472	1470	1456	No
Pru 302	04030-10131	1/18/98	Feb-98	1422	1419	1405	No
Pur 303	04030-10132	1/21/98	Feb-98	1411	1419	1405	No
Pru 304	04030-10133	1/15/98	Feb-98	1429	1437	1423	No
Pru 305	04030-10134	1/5/98	Feb-98	1381	1408	1394	No
Pru 306	04030-10135	1/9/98	Feb-98	1443	1452	1438	No
Pru 307	04030-11501	5/20/98	Oct-98	1436	1400	1386	Yes
Pru 308	04030-11502	5/24/98	Jul-98	1408	1378	1364	Yes
Pru 309	04030-11503	5/14/98	Sep-98	1385	1415	1401	No
Pru 310	04030-11504	5/11/98	Jul-98	1430	1411	1397	Yes
Pru 311	04030-11505	5/17/98	Oct-98	1439	1416	1402	Yes
Pru 312	04030-11506	5/7/98	Jul-98	1496	1409	1395	Yes
Pru 320	04030-12395	9/24/98	Dec-98	1370	1406	1393	No
Pru 321	04030-12290	10/4/98	Feb-99	1400	1431	1418	No
Pru 322	04030-12291	8/28/98	Jan-99	1371	1418	1405	Yes
Pru 323	04030-12292	9/7/98	Oct-98	1383	1410	1397	Yes
Pru 324	04030-12293	9/9/98	Oct-98	1363	1409	1396	No
Pru 325	04030-12294	10/6/98	Jan-99	1420	1469	1456	No
Pru 326	04030-12295	9/13/98	Feb-99	1444	1431	1418	Yes
Pru 327	04030-12296	10/9/98	Jan-99	1395	1431	1418	No
Pru 328	04030-12297	9/27/98	Oct-98	1432	1417	1404	Yes
Pru 329	04030-12298	10/13/98	Nov-98	1353	1406	1393	No
Pru 330	04030-12299	10/16/98	Nov-98	1347	1406	1393	No
Pru 331	04030-12396	10/11/98	Nov-98	1395	1430	1417	No
Pru 332	04030-12397	10/19/98	Jan-99	1337	1393	1380	No
Pru 333	04030-12398	10/21/98	Jan-99	1318	1373	1363	No
Pru 334	04030-12399	10/2/98	Jan-99	1415	1451	1438	No
Pru 335	04030-12300	9/4/98	Oct-98	1341	1382	1369	Yes
Pru 336	04030-12301	9/2/98	Oct-98	1378	1380	1367	Yes
Pru 337	04030-12400	9/30/98	Jan-99	1433	1452	1439	No
Pru 340	04030-12401	9/22/98	Oct-98	1403	1417	1404	No
Pru 341	04030-12302	8/30/98	Oct-98	1364	1367	1354	Yes
Pru 344	04030-12402	9/19/98	Oct-98	1391	1431	1418	No
Pru 345	04030-12403	9/8/98	Oct-98	1379	1413	1400	No
Pru 346	04030-12404	9/15/98	Nov-98	1375	1418	1405	No
Pru 349	04030-12405	9/17/98	Oct-98	1388	1419	1406	No
Pru 350	04030-12406	9/10/98	Oct-98	1372	1413	1400	No

The first six of the “300-series” wells were drilled in January 1998. Within a month these wells were primed and put into production. Oil rates increased progressively over the next five quarters (Fig. 2-19) with increasing monthly oil rates closely following additional wells coming on line (Fig. 2-18) and substantial increases in steam injection rates. The peak oil rate of 458.5 bopd reached in March 1999 relates directly to nearly all 37 cyclic wells by that time having been freshly steamed and put into production. The oil rate remained relatively flat around 400 bopd for the next 12 months before shooting up from 425.1 bopd in February 2000 to 742.3 bopd in March. Since that time the oil rate has declined gradually to about 550 bopd, but rose slightly in March 2001 to 619 bopd. The pronounced increase in oil rate in early 2000 coincides with both the onset of steam flood in the "300-series" patterns and the initiation of on-site metering of fluids. There was a sudden increase in pilot oil rates at exactly the same time.

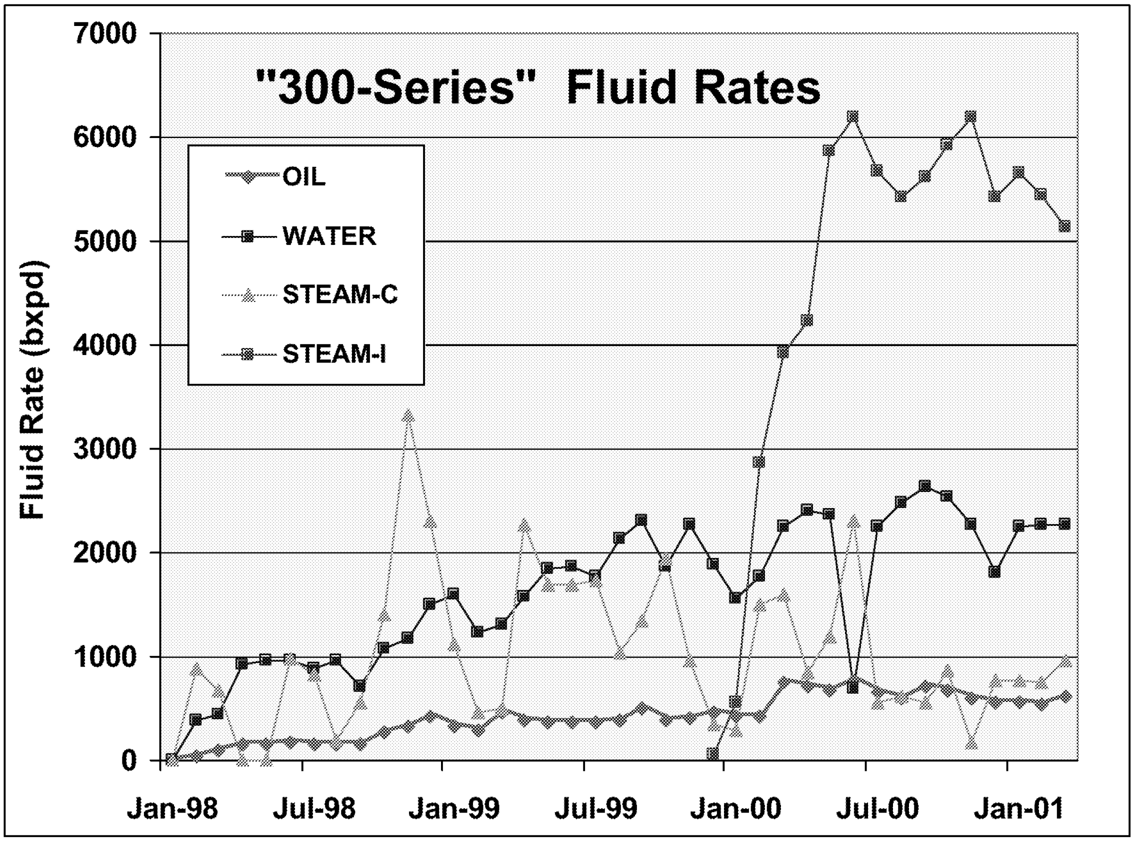

Figure 2-19: Daily average fluid rates for the "300-series" wells produced in cyclic mode through December 1999 and in steam flood thereafter.

By the end of December 1999, just prior to the conversion of the entire property to steam flood, the cumulative oil production from the "300-series" Stage 5 cyclic wells had reached 201,648 bbls. An additional 935,941 bbls of water was produced with the oil giving an OWR of 0.22. A total of 795,882 bbls of steam was injected in the cyclic wells resulting in an OSR of 0.25.

The "300-series" wells all had been completed as "open-hole" producers with slotted liner through the entire Monarch Sand pay zone above the OWC. Therefore, in forming the new steam flood patterns it was necessary to drill and complete ten additional injectors on the property (Fig. 2-20, Table 2-7). Each are positioned near the centers of their respective patterns and are numbered to reflect the pattern, Pru I2-5 through I2-14. Also three additional temperature observation wells were drilled. Pru TO-5 is situated in the southeast quadrant of *pattern 10* in the extreme northwest corner of the property. Pru TO-6 is in the southwest portion of the property near the join of *patterns 3, 6 and 7.* Pru TO-7 is in the northeast near the northern edge of *pattern 12* and immediately south of the Nevada lease. These three additional temperature observation wells complement the four existing wells within the pilot. The capital investment in the 13 new wells alone is about $889,000. Even though the new steam flood patterns were monitored as a component of the overall Class 3 oil demonstration project, Aera Energy LLC has made the investment alone without any financial contribution from the DOE project.

In converting the "300-series" producers to steam flood, the wells were arranged into ten two-acre nine-spot patterns surrounding the four-pattern pilot in the center of the Pru Fee property (Fig. 2-20). The pilot patterns are numbered from *pattern 1* in the northwest corner to *pattern 4* in the southeast corner. The ten new "300-series" patterns begin with *pattern 5* due south of *pattern 4* and proceed clockwise around the pilot patterns ending with *pattern 14* immediately east of *pattern 2*. There are no new patterns to the east and southeast of *pattern 4*. Otherwise, the entire property is covered with nine-spot patterns that on the whole mimic the configuration of the pilot patterns. All of the patterns are rough squares about 250-300 ft on a side. In forming the four patterns along the western edge of the property (patterns 7 through 10) it was necessary to incorporate 11 existing producers in the adjacent Kendon property, also operated by Aera Energy LLC. These Kendon wells are (from south to north) E-5, 608, 610, C-5, B-5, 712, 852, 713, 851, 718, and 716. All are within 50 ft of the Kendon-Pru boundary.

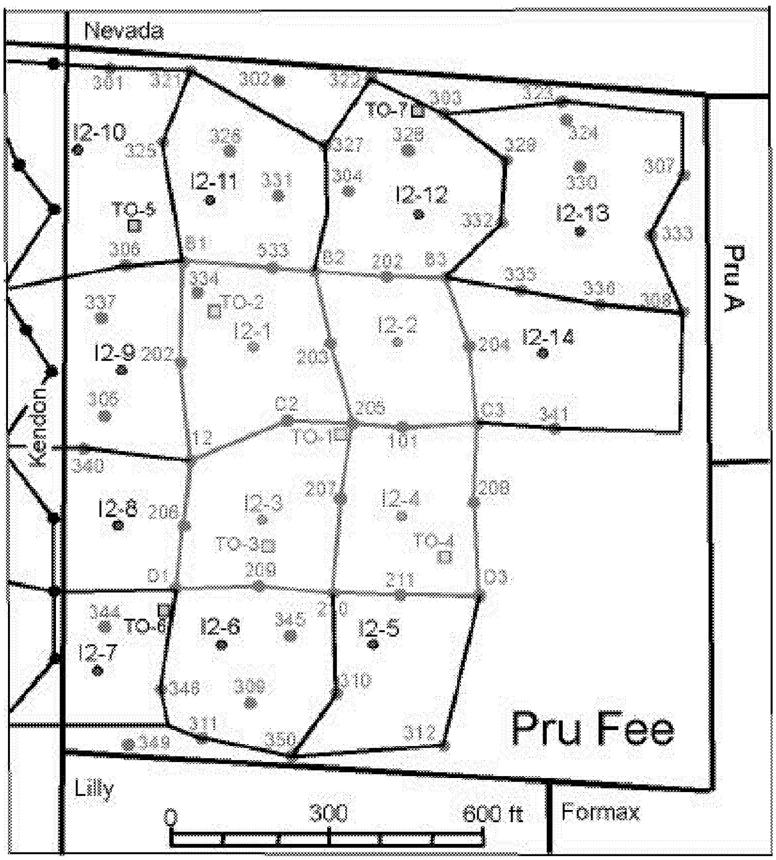

Figure 2-20: Array of new steam flood patterns developed early in 2000 linking the "300-series" and some pilot producers into 10 additional nine-spot patterns. The patterns are numbered after the injectors (I2-x) shown in red-filled open circles.

In order to provide sufficient steam to the existing wells and the 10 new injectors, additional steam facilities were installed in December 1999. The facility improvements involved relocating an existing generator to the adjacent Kendon lease and running a steam line from Kendon to Pru Fee. New steam splitters with metering facilities were installed on Pru Fee to manage the increased steam. The capital cost of relocating the generator was budgeted at $182,000; the new steam line and steam splitters cost about $479,000. The DOE project did contribute a small portion of the costs for increasing the volume of steam available to the Pru Fee property. The total budgeted cost of the expansion of the steam flood production on the Pru Fee property was $1,550,000.

At the time the four-pattern steam flood pilot was designed and implemented, the price of San Joaquin heavy crude was considerably less than $15/bbl and the economics of the steam flood scheme was still untested. The injectors were completed such as to put the steam into the lower half of the zone of presumed highest oil saturation. Narrow (55-60 ft) injection intervals were adopted with an average stand off from the top of the Monarch Sand and the OWC of 48.8 ft and 166.8 ft, respectively. The steam injection flux was between 0.7 and 1.4 bspd/naf. This conservative strategy was intended to yield favorable oil rates while keeping operating costs to a minimum, as required by the then prevailing net present value (NPV) of the property.

Table 2-7: Perforated intervals in the ten new steam injection wells

Injector	# perfs	Top Monarch	Top perf	Base perf	OWC	Inj. Interval	Upper SO	Lower SO	Spacing
I2-1	6	1057.0	1104.0	1160.0	1365.0	56.0	47.0	205.0	9.3
I2-2	6	1088.0	1127.0	1174.0	1362.0	47.0	39.0	188.0	7.8
I2-3	6	1103.0	1149.0	1209.0	1358.0	60.0	46.0	149.0	10.0
I2-4	6	1087.0	1150.0	1206.0	1331.0	56.0	63.0	125.0	9.3
I2-5	5	1151.0	1164.0	1248.0	1352.5	84.0	13.0	104.5	16.8
I2-6	8	1136.5	1174.0	1324.0	1381.5	150.0	37.5	57.5	18.8
I2-7	6	1123.5	1154.0	1300.0	1388.5	146.0	30.5	88.5	24.3
I2-8	5	1105.0	1133.0	1308.0	1370.5	175.0	28.0	62.5	35.0
I2-9	11	1070.0	1086.0	1354.0	1392.0	268.0	16.0	38.0	24.4
I2-10	8	1097.0	1131.0	1344.0	1449.0	213.0	34.0	105.0	26.6
I2-11	11	1096.5	1107.0	1398.0	1429.0	291.0	10.5	31.0	26.5
I2-12	9	1068.0	1123.0	1305.0	1344.5	182.0	55.0	39.5	20.2
I2-13	10	1069.0	1078.0	1292.0	1331.5	214.0	9.0	39.5	21.4
I2-14	6	1084.0	1095.0	1282.0	1339.0	187.0	11.0	57.0	31.2

Note: All well depths are in feet down-hole, not TVD. *Injectors 1 - 4: Pru steam flood pilot; Injectors 5-14: 300-series patterns*

By the time of conversion of the "300-series" wells from cyclic to steam flood mode other factors governed optimal production. The principal factor was the sharp increase in the price of Midway-Sunset heavy crude to the upper teens and lower twenty's, and rising. Also the viability of steam flood as a commercially successful recovery method in marginal, low-dip portions of the Monarch Sand was proven in Stage 4 and Stage 5 of the project. Furthermore, it was clear from the temperature observation wells that the steam was staying in the formation very close to where injected, not rising into the overlying oil-free Etchegoin Formation. Very thin and apparently discontinuous diatomite lenses seemed to be partially effective in holding the steam within the sand reservoir. Therefore, a decision was made to adopt a less conservative strategy in placing the perforations in the ten new injectors. Although an effort was made to avoid injecting steam into high Sw parts of the reservoir, the new injectors have shorter standoffs from the top of the Monarch Sand and the OWC, and the injection interval encompasses most of the pay interval (Table 2-5). It was anticipated that the less than optimal placement of the injected steam, from the standpoint of operational costs, would be offset by larger oil rates and total ultimate oil recovery, both desirable economic factors given the increased NPV of the Pru Fee crude in late 1999 and early 2000. The high market price of Midway-Sunset crude continued through March 2001.

The steam flood performance factors (Fig. 2-21), the oil-steam (OSR) and oil-water (OWR) ratios, were generally good during Stage 5 cyclic recovery. However, with the onset of Stage 6 steam flood the OSR dips to a relatively uniform and unfavorable 0.11 reflecting the very aggressive steam injection schedule maintained through early 2001. The large volumes of steam injected after January 2000 is enhancing recovery across all of the property, greatly improving OSR in the pilot (Fig. 2-16), but at the temporary expense of efficiency in the surrounding patterns.

From January 2000 through March 2001 the "300-series" steam flood patterns had produced a total 302,178 bbls of oil. To produce this volume of oil 2,236,295 bbls of steam was injected into the 10 injector wells and an additional 422,621 bbls used in cyclic stimulation of the producers. About 16% of the total steam injected was used to stimulate the producers. The OSR for the Stage 6 steam flood is 0.11. The volume of water produced is 1,096,923; the OWR is 0.28.

Over the entire period of production from the 37 "300-series" wells through March 2001 the cumulative oil yield is 503,826 bbls, which in just over two years nearly matches the oil production from the considerably older Pru Fee steam flood pilot. Considering only production from the Monarch Sand reservoir (Table 2-1), the DOE-sponsored Class 3 demonstration project had been responsible for over a million barrels of incremental oil from the 40 acre property and the oil rates from ongoing steam flood operations were showing no signs of diminishing.

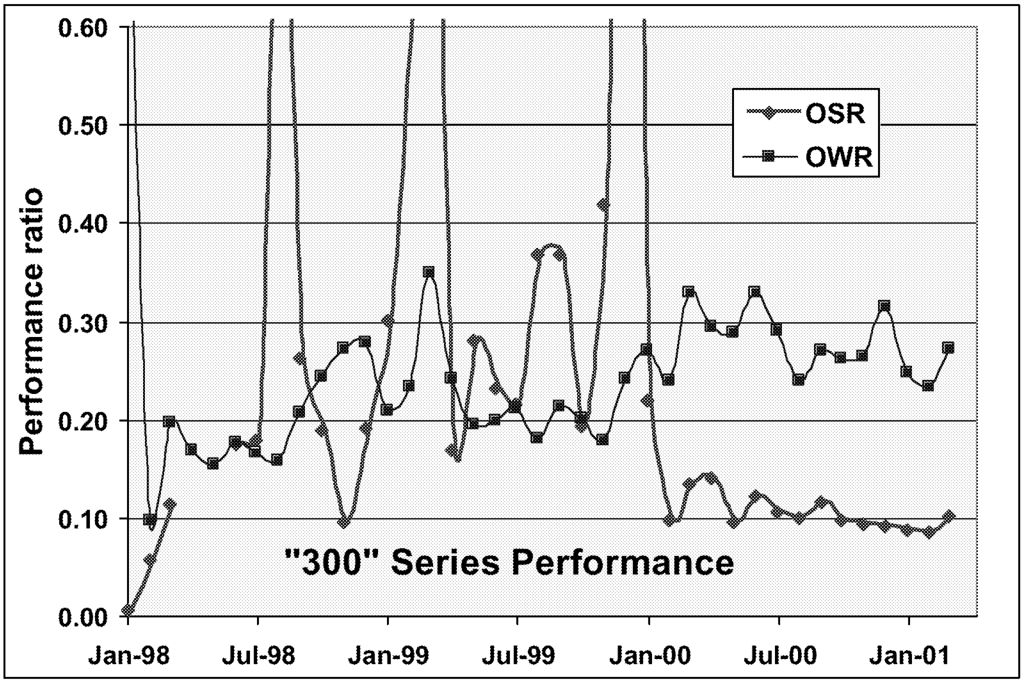

Figure 2-21: Performance ratios for the "300-series" producers. The OSR, which is highly variable during the Stage 5 cyclic operation through December 1999, drops to a poor 0.10 during the Stage 6 steam flood. This is due to the very aggressive steaming (1.5 bspd/naf) of the new patterns during the first year of this recovery mode. The OWR improves just slightly.

Chapter 3

Characteristics of the Monarch Sand Reservoir

Introduction

The Midway-Sunset field produces from multiple reservoirs that range in age from Oligocene to Pleistocene, but most of the heavy oil is produced from upper Miocene reservoirs (Hall and Link, 1990; Lennon, 1990). The reservoir at the Pru Fee property is the uppermost Miocene Monarch Sand.

The stratigraphic nomenclature (Fig. 3-1) applied to this part of the Midway-Sunset field is a combination of formal units, which are recognized at the surface and in the subsurface, and informal units, which are identified mostly in the subsurface. The stratigraphic nomenclature of Callaway (1962) and Foss and Blaisdell (1968) has been adopted in this project as it is the nomenclature in most common use in the field. The Monarch Sand is an informal unit within the Belridge Diatomite Member of the Monterey Shale (Gregory, 1996; Fig. 3-2). It typically overlies the informal Republic, Williams, and Leutholtz sands (in descending order). The Monarch Sand normally is overlain by the upper part of the Antelope Shale and the Reef Ridge Shale. However, at the location the Pru Fee property on the SW flank of the Spellacy anticline a regional unconformity removes the Reef Ridge Shale and the top of the Antelope Shale placing the Pliocene Etchegoin Formation directly on the Monarch Sand. Although no well has penetrated below the Monarch Sand at the project area, there is reason to believe that the underlying stratigraphic section is similar to that of nearby areas.

During the course of the project, as additional wells were drilled, logged and analyzed, the essential characteristics of the Monarch Sand reservoir at Pru Fee became clearer and more detailed. Each new set of data permitted a revision of the former stratigraphic and petrophysical model. However, the broad aspects of the model largely were verified in each new revision. The richer understanding of the reservoir dictated a fine-tuning of operational practices on site, not any substantial change in the steam flood strategy chosen at the onset of the project. The evolving development of the stratigraphic and petrophysical model of the reservoir was very much a group effort involving most of the project team members.

In building the model for the Monarch Sand reservoir at Pru Fee the team was able to draw on a wealth of external knowledge in the literature, particularly the excellent review by Gregory (1996), and the experience of team members in other AWE properties in the Midway-Sunset field. The decision to take a core in the center of the property, Pru-101, at the very start of the project proved critical to all subsequent analysis. It was the quality of the reservoir evident in the core that lead to the favorable economic assessment recommending that the project to go forward from the evaluation phase into the steam flood demonstration. By the end of the project in March 2001, a total of 57 new wells penetrating the Monarch Sand had been drilled on the property of which 40 had been logged. There were twenty logged wells by early 1997, an addition 7 in 1998 and by early 2000 still 13 more. This report will not trace the evolution of the stratigraphic and petrophysical models developed, but rather present our current understanding of reservoir.

Description and Petrophysical Analysis of Pru-101 Core

The Pru-101 well, located near the center of the Pru Fee property, entered the top of the Monarch Sandstone at a depth of 1100 ft, passed through 268 ft of dominantly medium and coarse-grained, oil-stained sand to penetrate the oil-water contact at 1368 ft depth. The base of the Monarch Sandstone was not reached in the well. About 96% of the core recovered from the Monarch Sandstone is highly porous oil-stained sand. The remaining 4% of the core is non-reservoir diatomaceous mudstone and fine sand.

The cored interval through the Monarch Sand consists of major fining-upward sequences. A typical multi-bed sequence begins with a pebble or granule sand that progresses upward through coarse grained sand, medium sand, and perhaps interbedded bioturbated or muddy sand before passing abruptly into another pebble or granule sand that begins the next sequence. Overall, however, the full section from the oil-water contact to the top of the Monarch Sand (1106.4 to1368.6 ft.) coarsens upward. which is consistent with a prograding shoreline and progressive filling of the basin. The muddy fine sands, silts and diatomite capping many of the sand flow units are deposited from suspension as the flow wanes. The absence of any true marine clays suggests short periods of time between successive debris flows and turbidites.

Scope of analysis

The Pru-101 well was cored to obtain additional information about rock quality and fluid saturations on the Pru lease. Specifically, the well was cored to:

- determine reservoir quality (Sw, permeability, net-to-gross, porosity)
- understand the controls on reservoir quality (grain size, sorting, mineralogy, clay volume)
- assess the number and quality of steam barriers (permeability, thickness, lateral extent)
- develop a log model to calculate rock properties and saturations in uncored wells
- compare reservoir quality with offset wells including the Kendon-405 and Pru-533.

Several types of core data were analyzed to characterize the reservoir including:

- A visual core description to characterize the lithofacies present in the core, their relationship to one another, and their depositional environment.
- Routine core measurements to understand (1) the distribution of porosity, permeability, and fluid saturations in core and (2) how to use these values for calibrating the log saturations.

- X-ray diffraction to identify and quantify the minerals present in the whole rock and clay fractions.
- Thin-section descriptions to characterize pore geometries, controls on reservoir quality, and susceptibility to formation damage.

The core data were then related to the logs through:

- A petrophysical analysis of the reservoir to calculate porosity, permeability, and saturations in uncored wells.

Finally, the data were used to make projections about reservoir performance through:

- An analysis of sand and barrier continuity to assess the connectivity of sands and lateral extent of steam barriers.
- An assessment of water saturation and well performance with special emphasis on the impact of a transition zone in the reservoir.

Visual Core Description

A total of 225' of core recovered from the Pru-101 well (Fig. 3-3) was described in Bakersfield in October, 1995. The core is dominated by poorly to very-poorly sorted, massive to pebbly, oil-stained sands (Figs. 3-4 to 3-6) and is divisible into six lithofacies types, summarized below. The percentage of each lithofacies observed in the core is indicated in brackets.

- **Pebble sands** [10%] contain 10-15% granules and 10-40% pebbles with occasional cobbles up to 4 by 4 inches in size. All of the sands are matrix-supported with clasts of subangular-to-subrounded plutonic, volcanic, and metamorphic rocks that have the same aggregate mineralogy as the matrix sand. Intervals consisting only of pebbles and cobbles are inferred to be pebble sands that have had their matrix sand washed away during coring. Graded bedding and pebble imbrication are rare.
- **Granule sands** [16%] contain 10-25% granules and 5-20% pebbles. Some intervals contain faint laminae dipping up to 20 degrees. Granule sands are distinguished by a co-equal percentage of granule and pebble-sized rock clasts and less intense pebbling.
- **Coarse-grained sands** [43%] contain 5-20% granules and <5-20% pebbles. Large pebbles and thin layers (1-2 inches) of intense pebbling are occasionally seen. Sedimentary features include siltstone rip-up clasts, imbricated clasts, inclined and horizontal bedding, thin siltstone interbeds, and carbonaceous material. Coarse sands are characteristically massive with small, widely-dispersed pebbles.
- **Medium-grained sands** [27%] contain <5-15% granules and <5% pebbles. Sedimentary features include thin interbedded siltstone and fine sand layers which often have basal lags of granules and carbonaceous material, rip-up clasts, and faint horizontal to gently dipping laminae. Medium-grained sands are characterized by a distinctly finer grain size than other productive sands and a near absence of pebbles.
- **Muddy to bioturbated fine sands** [4%] range from mottled, bioturbated, oil-stained sand and mudstone in the Etchegoin Formation (overlying the Monarch) to tan,

lightly oil-stained, siltstone and fine micaceous sand within the Monarch. Sedimentary features include horizontal to inclined burrows, carbonaceous fragments, and interbeds of medium-grained sand. These sands are distinguished by their bioturbation, light oil staining, large silt/clay fraction, and permeabilities that are lower than productive sands. Within the Monarch, there are 17 different intervals of this lithofacies, ranging from 0.1-0.6 ft in thickness.

- **Mudstones** form gray, unstained, massive to laminated intervals primarily in the overlying Etchegoin Formation. Sedimentary features include inclined burrows, calcareous pebbles, and conjugate faults with very minor displacement.

After dividing the core into lithofacies types, a histogram was created to show the vertical changes in these lithofacies and facilitate their grouping into fining and coarsening upward sequences. The histogram is dominated by fining-upward sequences that can be subdivided into individual turbidite flows. For example, the sequence from 1230.6-1240.7 ft is composed of three individual turbidites: (1) a pebble sand to medium-grained sand from 1240.7-1235.3 ft, (2) a coarse sand to medium grained sand from 1232.3-1235.3 ft, and (3) another coarse sand to medium grained sand from 1230.6-1232.3 ft. Applying this technique to each fining-upward sequence yields a mean thickness of 2.3 ft for individual turbidites in the Monarch (Fig. 3-7) with a range of 0.1 to 6.3 ft.

Inverse grading occasionally generates a coarsening-upward sequence between fining-upward sequences. However, the dominance of fining upward sequences combined with diagnostic aspects of the core (massive to parallel laminated sands, rip-up clasts, thin suspension deposits, flame structures, low clay content) confirm that the Monarch was deposited as a series of high-density turbidites. Overall, the sequence coarsens-upward from the oil-water contact to the top of the Monarch. This is clearly shown by a decrease in the amount of coarse and medium grained sands above about 1285 ft. This change is consistent with a prograding shoreline and progressive filling of the basin, or alternatively the approach of the point source of the sands on the northward-transiting Salina Block.

The sands are very poorly sorted, as is evident in the grain-size analysis of six core samples carried out by CoreLab (Fig. 3-8). The size distributions are strongly skewed towards the fine fractions such that the sands are virutally indistinguishable in their less than fine sand (Phi>2.0) tails. A medium sand lithofacies (sample 1257.5 ft) is a fine sand with a large component of medium sand (Phi=1.0). A coarse sand lithofacies (sample 1111.5 ft) is a medium sand and finer fractions with a substantial component of coarse sand (Phi = 0.0). And so on. Several of the coarser lithofacies (samples 1239.5 ft and 1367.5 ft) are strongly bimodal with pebbles and coarse components mixed with the finer fractions.

Within the general vicinity of the Pru Fee property the sedimentologic character of the Monarch Sand is little changed. Granular and coarse sand lithofacies dominate the section (Fig. 3-9) and variations are principally in the portions of pebbly and cobble sands or fine sand and mudstones (diatomites). The Crocker Canyon Sand (Fig. 3-10 to 3-12), which is exposed in outcrop at the northern end of the Midway-Sunset field about 40 miles from the Pru Fee property, is extremely similar in terms of sedimentology and fine-scale stratigraphy to the Monarch Sand in the Pru-101 core. Although clearly separate sand bodies, these two sands are coeval facies equivalents (Fig. 3-2).

In providing a broader view of the internal geometry of the sand body than that possible in the Pru-101 core, the Crocker Canyon outcrops are very instructive. These show a stacked sand body with a predominance of sand-on-sand contacts. The tops of virtually all beds are scoured. Diatomite layers within the sand body represent mere remnants preserved beneath scour surfaces. Thus, they are very discontinuous, generally extending laterally only a distance of feet or at most tens of feet. Diatomite rip-up clasts up to several feet in size embedded in the sand are common.

The proposed depositional model is a steep-faced fan-delta prograding onto a shallow marine shelf. Periodic remobilization of fan-delta deposits (probably debris flows) generates turbidity currents (Nemec, 1990) that flow downslope to deposit the Monarch Sand. The muddy fine sands capping many of the turbidites are deposited from suspension as the flow wanes. The absence of any true marine clays (pelagic or hemi-pelagic) indicates short periods between successive turbidites.

The interpretation presented here compares favorably with the conclusions of Webb (1978). He states that the Monarch Sand in T32S, R23E, Section 26 C is composed of turbidites ranging from 0.3-5 ft thick with an average thickness of 2 ft. Webb identifies the presence of "diatomite" layers composed of diatoms and fine-grained clastics that are equivalent to the muddy to bioturbated fine sands described in this study. He also describes the Monarch as an overall coarsening-upward sequence generated by a prograding fan.

Analysis of Routine Core Measurements

CoreLab made routine core measurements on 246 samples (Table 3-1) using a confining pressure of 500 psi, which approximates the net effective overburden stress in the reservoir. A cross-plot of permeability vs. porosity using these core measurements shows that each lithofacies occupies a specific field. Pebble sands show a large amount of dispersion because the dominant heterogeneity (pebbles) is often larger than the sample size of the core plug (about 1.5 inches). Granule and coarse-grained sands show progressively higher porosities and permeabilities (Fig. 3-13) as a result of fewer pebbles and little clay. Medium-grained sands have higher porosities due to better sorting, but lower permeabilities due to finer grain size and the inclusion of suspended clays.

Bioturbated to muddy sands display permeabilities which are at least two orders-of-magnitude lower than productive sands. This should be sufficient to make these fine-grained, clay-rich rocks barriers to vertical steam migration if they are sufficiently thick and laterally extensive. Porosities reported for the mudstones and bioturbated to muddy sands (31-51%) reflect the high micro-porosity of these samples.

Water saturation (Sw) and *oil saturation* (So) values from the core (Fig. 3-14) are of limited value due to the drainage of liquid from samples, possible invasion during coring, and transition zone penetration. However, some statistics are still useful, especially the Sw minimums which are about 16% for coarse and granule sand, 18% for medium sand, and 20% for pebble sand. These values follow the same trend as the permeability distribution and provide a good indication of *irreducible water saturation* (Swirr). Similarly, the So minimums of around 13% provide a good measure of Sor.

Table 3-1: Petrophysical properties of Pru-101 core samples by lithology

	Lithology	PERMEABILITY (md)	POROSITY %	Porosity Elkins	So % Elkins	Sw % Elkins	% core
1	Mudstone	NA	NA	NA	NA	NA	0
2	Fine sand	1195.4	36.6	34.8	47.7	52.3	4.4
3	Medium sand	2177.9	33.0	30.6	58.2	41.8	26.8
4	Coarse sand	2967.1	31.4	27.3	58.3	41.7	42.0
5	Granular sand	2867.0	30.3	25.9	55.9	44.1	16.6
6	Pebbly sand	2277.4	28.6	24.0	54.4	45.6	10.2
	Total core =	**2677.6**	**31.6**	**27.9**	**57.0**	**43.0**	**100.0**

Analysis of X-Ray Diffraction Data

In order to relate sand quality differences in the Pru-101 well to differences in whole rock and clay mineralogy, 17 samples were chosen for X-ray diffraction (XRD). The results of this work show that productive sands have an average composition of 36.8% quartz, 16.8% potassium feldspar, 37.0% plagioclase feldspar, 7.4% biotite, 0.5% pyrite, and 1.6% clay. Productive sand samples have moderate amounts of clay + biotite (4.7 to 15.7%) which increases with decreasing grain size and permeability. The gross abundance of quartz, plagioclase and potassium feldspar remains relatively constant irrespective of grain size. This suggests that the individual mineral grains in the finer-grained rock types were derived from the same parent rock as the rock fragments in the coarser-grained sands.

The muddy to bioturbated fine sand and mudstone samples have substantially more clay (31.9 to 41.4 %) and pyrite (4.5 to 4.8%) than the productive sands. The clays are composed of mixed-layer illite-smectite, chlorite, and trace amounts of kaolinite. Samples from an oil-depleted zone in the well (1102-1113 ft) show a slight increase in illite-smectite at the expense of chlorite and biotite. This is probably a diagenetic alteration caused by steaming (Pennel and Horton, 1994).

There appears to be a rather poor relationship between permeability and % clay, largely because all of the productive sands have such a low percentage of clay. However, the relationship between permeability and % biotite + clay is significantly better. Sands with permeabilities below 1000 md can be expected to have > 15% biotite + clay.

Analysis of Thin-Sections

Thin-sections were cut from 33 samples and evaluated to assess reservoir quality and formation damage potential. The results of this work show that samples with the highest reservoir quality are matrix-poor sandstones that combine the most open packing, best sorting, and coarsest mean grain size. Pore geometries in these sands are dominated by well-connected interparticle macropores.

Grain size, sorting, and rounding indicate post-depositional crushing of feldspars. This results in fine grained, extremely angular fragments especially in medium- to coarse-grained sandstones. The presence of these fragments introduces a significant fine tail to the grain size distribution and indicates that these rocks are highly susceptible to fines migration. In contrast, crushing is minor in matrix-rich samples, probably because the matrix provided support for the grains and helped dissipate stresses at grain-to-grain contacts.

Chemical diagenesis in sands is minor and is generally limited to (1) alteration of volcanic rock fragments to chlorite and smectite, (2) local dissolution of unstable framework grains, and (3) expansion and alteration of biotite flakes to chlorite, smectite, and pyrite. These processes should have a minor affect on productive sands due to their large pore throats and the relatively small amounts of clay (<4%) and reactive minerals (biotite and volcanic rock fragments) available for conversion to smectite.

Mudstones and bioturbated to muddy fine sands contain abundant clay present as detrital matrix and alterations of rock fragments. These sands also contain trace to minor amounts of sponge spicules and diatoms. Pore geometries are dominated by interparticle micropores that are substantially smaller than productive sand pores.

Petrophysical Analysis

A log analysis model for the Monarch Sand on the Pru lease was developed to calculate effective porosity, water saturation, non-reservoir volume, pebble volume, and permeability. The model can be applied to any well with a minimum logging suite of resistivity, density, and neutron curves. Information from the model will help (1) determine the net hydrocarbon feet available for production and (2) extract lithofacies information that can be used to make decisions about steam flooding or cycling wells. The model was calibrated to depth-shifted core from the Pru-101 well; it also was applied in the nearby Pru 533 well as a check.

Porosity: As discussed previously, core porosities were measured at net effective overburden stress (500 psi) and should approximate reservoir conditions.

1) To calculate the *density porosity* use:

$$\phi_d = \left(\rho_{ma} - \rho_{\log}\right) / \left(\rho_{ma} - \rho_f\right)$$

where: ρ_{log} = bulk density from the log

ρ_{ma} = matrix density of 2.69 gm/cc from XRD results

ρ_f = fresh water fluid density of 1.0 gm/cc

2) In undepleted intervals calculate the *effective porosity* using an average of the neutron and density:

$$\phi_e = (\phi_d + \phi_n) / 2$$

where: ϕ_d = density porosity in decimal fraction

ϕ_n = neutron porosity in decimal fraction

3) In the oil-depleted intervals the *neutron porosity* will be too low and the *density porosity* will be too high. Depleted intervals are defined here as those in which the density porosity reads higher than the neutron by more than 3.0 pu. When this condition is met, the following equation should be used to calculate effective porosity:

$$\phi_e = (0.66 * \phi_d) + (0.33 * \phi_n)$$

Water Saturation: Determination of water saturation was greatly aided by coring and logging the aquifer. *Formation water resistivity* (Rw) was determined by direct measurement of water extracted from the core and a cementation exponent (m) was calculated from the logs in the aquifer. In addition, the log model was matched to core from both the aquifer (100% Sw) and the top of the reservoir (Swirr), lending confidence that the saturation model between these two points is accurate. This is important because through the transition zone of the Monarch both oil and water are lost from the core, making it difficult to accurately calibrate log saturation values.

Because of the low clay volume, there is little difference between a shaly sand equation, such as the Simandoux, and the Archie equation. Therefore, the Archie equation, which is also much simpler, was applied to the Monarch Sand in this study. The log model does not perform as well in the depleted zone due to the variable Rw caused by the presence of steam and condensed steam.

$$S_w = \left(\frac{R_w * a}{R_t * \phi_e^m} \right)^{\frac{1}{n}}$$

where:
- R_w = the formation water resistivity (0.55 @ 77oF)
- **a** = 1.0
- R_t = Deep Resistivity
- ϕ_e = Effective Porosity
- **m** = 1.80
- **n** = 1.80

Bulk Volume Water: Bulk volume of water (**BVW**) is defined as the quantity of formation water present in a unit volume of rock.

$$BVW = Sw * PHIE$$

On the Pru lease. it is estimated that there is no water production where BVW is less than 0.12; possible water production where BVW is between 0.12 and 0.18; and water production when BVW is greater than 0.18. Using these values as cutoffs, 131.5 ft of the Monarch in Pru-101 is below a BVW of 0.12 and 230.5 ft is below a BVW of 0.18.

Non- Reservoir Rock Volume: The XRD data show that there is less than 3.5% clay in the Monarch Sand. Because this small amount is difficult to resolve with the logs, the clay volume was combined with the silt volume into a single "non-reservoir rock" volume. This technique identifies those intervals of lower quality that are unlikely to contain economic oil saturation. The neutron porosity was chosen as the most reliable indicator of non-reservoir rock because of the difficulty in using a GR (feldspathic sands) or SP (little contrast between borehole and formation waters) in these sands.

$$\mathbf{V_{nr} = (\phi_n - 0.3)/\ 0.15}$$

where: $\mathbf{V_{nr}}$ = Volume of Silt + Volume of Clay
$\boldsymbol{\phi_n} \geq 0.30$
Deep Resistivity $\Leftarrow$ 20 ohm-meters
Shallow Resistivity $\Leftarrow$ Deep Resistivity

Pebble Volume: It is helpful to know the location of pebbly intervals in a well because these may help slow the upward movement of injected steam and they also have a lower recovery per unit volume. As pebbles increase in the reservoir, porous sands are replaced with dense pebbles, decreasing porosity. As a result, the pebble volume equation developed for the Monarch Sand uses density porosity as shown below.

$$\mathbf{V_{peb} = ((\phi_d * 100)^{-4.452}) * (10^{4.68})}$$

when: $\boldsymbol{\rho_b} \geq$ **2.23 gm/cc**

Permeability: As discussed previously, permeability is a function of grain size, sorting, and clay content in the Monarch. Given these controls, it is difficult to accurately calculate permeability from the logs. Logs do not make direct measurements of grain size and sorting, and they are unable to accurately resolve the small changes in clay content that cause large changes in permeability. Therefore, in this study, permeability was determined using values of Sw, porosity, and the volume of silt + clay calculated from the logs. Since all three of these parameters have a strong dependence on permeability, combining them into a single equation provides a reasonable permeability indicator. A Wyllie permeability equation (Slider, 1983) was modified and used here.

$$\mathbf{PERM} = \left\{\left[200^{1-(Vnr*0.7)}\right] * \left[\phi_e^{2.25} * \frac{(1-Swirr)}{Swirr}\right]\right\}^2$$

where: **Vnr** = Volume of Non-Reservoir Rock (Vsilt + Vclay)
$\boldsymbol{\phi_e}$ = Effective Porosity
$\mathbf{S_{wirr}}$ = Irreducible Water Saturation
$\mathbf{S_{wirr}}$ is 0.20 from the whole core analysis.

Sand and Barrier Continuity

Ideally, for efficient steamflooding, periods of sand deposition will be separated by long quiescent periods during which laterally-extensive muds can be deposited to form steam barriers. Unfortunately, this did not occur during Monarch deposition, and only thin, laterally discontinuous suspension deposits, which formed during waning turbidite flow, serve as potential barriers.

These suspension deposits will only be actual barriers where (1) they are thick enough to survive erosion by successive sand flows, and (2) have permeabilities that are about two orders of magnitude less than productive sands. Webb (1978) identified such an interval in the Monarch Sand of Section 26C. Core from this area contains about 5 ft of silica-cemented sands and thick "diatomites" (muddy fine sand deposited from suspension) with permeabilities of 2-3 md. These are interbedded with oil-stained sands over a thickness of 8-10 ft. Webb indicates that this interval can be correlated on logs and extends over an area at least 600 by 1000 ft. Steam injected beneath this "marker zone" remained below it based on data from temperature observation wells.

Unfortunately, no zones of similar thickness and low permeability were observed in the Pru-101 core. However, the log model does indicate one potential steam barrier through which no core was recovered. This interval, from 1208-1218 ft, is characterized by 40-95% silt and clay and probably consists of interbedded muddy fine sand and medium-grained sand. This interval may only be present over a small area because it is not apparent in the neighboring Pru 533 well.

Water Saturation and Well Performance

At the top of the Monarch reservoir in Pru-101 is a 14 ft thick oil-depleted interval that has a distinctly lighter oil stain than the underlying sand. This zone, which is also characterized by high permeabilities, low oil saturations, and neutron-density crossover on the logs, grades into the underlying undepleted zone over a distance of several feet. At the base of the reservoir, a sharp oil-water contact separates the oil sand in the Monarch from the underlying aquifer.

From the base of the oil-depleted zone to the oil-water contact, core and log data indicate a progressive increase in Sw. This is due to the presence of a long transition zone as indicated by a plot of core Sw (for samples with total liquids > 90%) vs. height above the oil-water contact by permeability band. Intuitively, the transition zone here should be short due to the high sand permeability. Capillary pressures of only 1 psi or so should result in irreducible water saturations (Swirr). Unfortunately, it takes over a hundred feet of rock column to obtain this pressure due to the small density difference between heavy oil (12 degrees API) and water (10 degrees API) in the reservoir. Using the equation Howc = (Pc / (.433 * rbrine - roil) where rbrine = 1.0 g/cc and roil = 0.98 g/cc, then at a capillary pressure (Pc) of 1 psi, Howc = 115 feet.

In the Pru-101 core, resistivity (Rt) values are observed to vary with the value of Sw. The correlation is such that Rt is only 35 OM at 30% Sw. However, at 20% Sw, Rt has more than doubled to 75 OM. This accounts for the apparent "step-change" in Rt above about 1220 ft on the logs. This explanation also means that above 1220 ft, the reservoir should be near Swirr and have water free initial production. This is supported by bulk volume water values below 0.12. Below 1220 ft, there will be a substantial loss of heat and a progressive increase in water production due to the increase in mobile water. This, coupled with lower oil saturations, will negatively impact steamflood economics in the bottom half of the reservoir.

Summary

1. Above the oil-water contact is a 150-foot transition zone that exists because of the small density difference between heavy oil and water in the reservoir. This transition zone contains mobile water which will absorb heat and be produced along with the oil. From the top of the reservoir (1100 ft) to about 1210 ft depth, water saturations are near irreducible and initial production should be water-free.

2. The only interval in the well that may be a laterally continuous steam barrier is from 1208 to 1218 ft. This interval is likely composed of interbedded muddy fine sand and medium-grained oil sand, although no core was recovered through it.

3. 96% of the core recovered from the Monarch consists of oil-stained sand. This includes 27% medium-grained sand, 43% coarse-grained sand, 16% granule sand, and 10% pebble sand. The remaining 4% of the core is comprised of non-reservoir mudstone and muddy to bioturbated fine sand.

4. Effective porosity, water saturation, non-reservoir rock volume, pebble volume, and permeability calculated using the Monarch Sand log model compare very well with core. The model, developed in this study using an AIT/LDT/CNL/GR tool suite, can be applied to any other Monarch Sand well with a resistivity, density, and neutron log.

5. The AIT logging tool recorded significantly higher resistivities from 1100-1210 ft in Pru-101 relative to offset wells with older standard dual induction (ILD) logs. Modeling indicates that shoulder-bed effects could explain the discrepancy over the top 12 ft of this interval, but cannot account for the entire interval. The higher resistivities result in a decrease of 5-10 saturation units relative to offset wells. Based on in-house discussions and industry consensus, the AIT should be more accurate than the older ILD.

6. X-ray diffraction (XRD) data show that the mineralogic composition of productive sands is fairly uniform and consists of quartz (36%), plagioclase (36%), K-feldspar (17%), biotite (9%), pyrite (1%), and clay (1%). The feldspar grains and rock fragments have been crushed into mobile fines that could cause plugging or "flour sand" production, especially at high flow rates.

7. Visual inspection of the log curves from Pru-101 and Pru 533 indicates that resistivities less than about 13 ohm-meters are definitely non-reservoir. These intervals include both silty sands and higher quality wet sands, as well as mudstones. A review of the log curves from Pru A-2, Pru 13, and Pru A-5 indicate that a similar cut-off is applicable in these wells.

8. The sands were deposited as turbidites and minor, associated debris flows based on the suite of sedimentary structures observed in core and the arrangement of sands into a series of fining-upward sequences. Given the high net-to-gross (0.96) observed in Pru-101 core, reservoir continuity likely will be excellent. However, steam barrier continuity

will be poor because potential barriers are thin and commonly eroded by successive turbidite flow units.

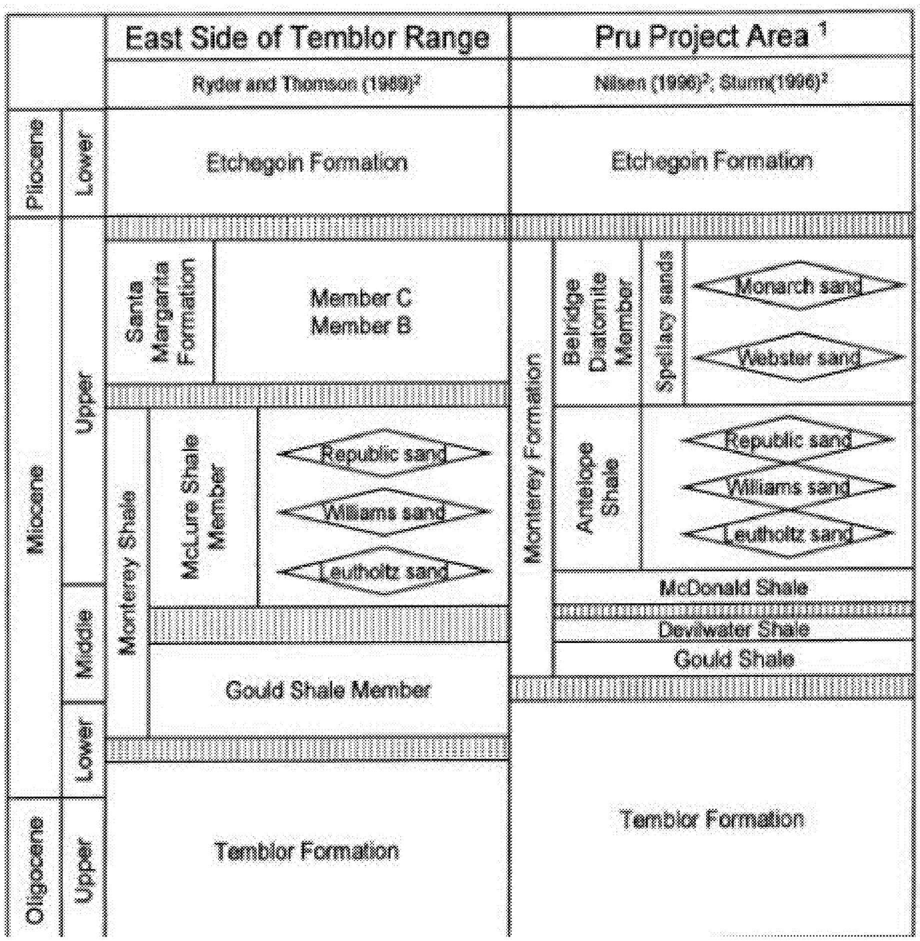

Figure 3-1: Stratigraphic nomenclature and relative positions of major sand bodies within the Monterey Formation on the western edge of the southern San Joaquin Basin. The Monarch Sand is one of several sand bodies embedded within the Belridge Diatomite Member. Collectively these also are known as Spellacy Sands.

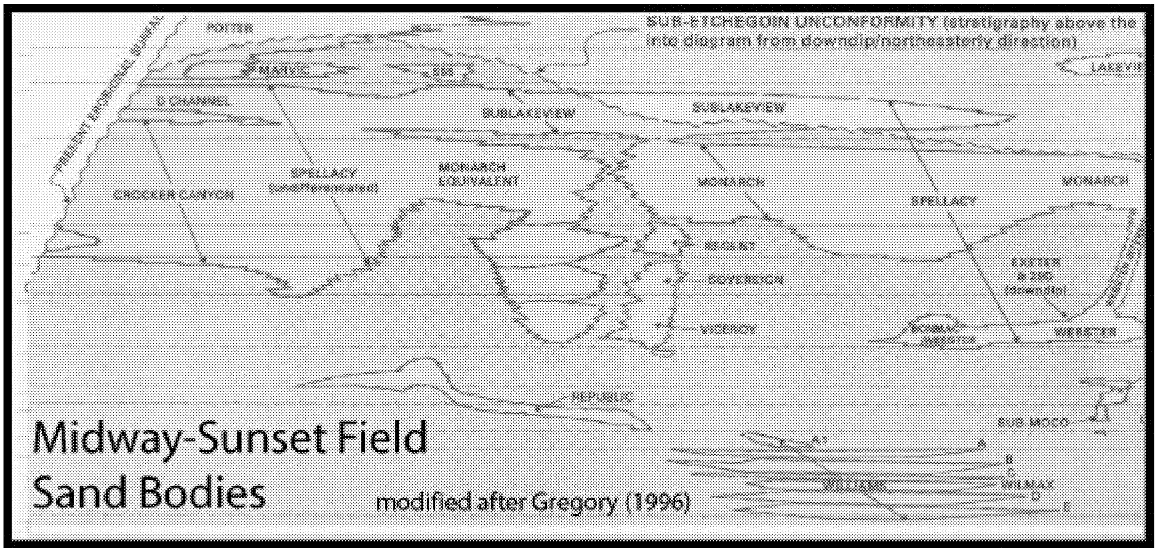

Figure 3-2: Spatial relations among the Spellacy Sands along the length of the north and central parts of the Midway-Sunset field. The sand bodies, which are encased in diatomite, appear to have been emplaced within the deeper parts of the basin from relatively proximal point sources, such as fan-deltas.

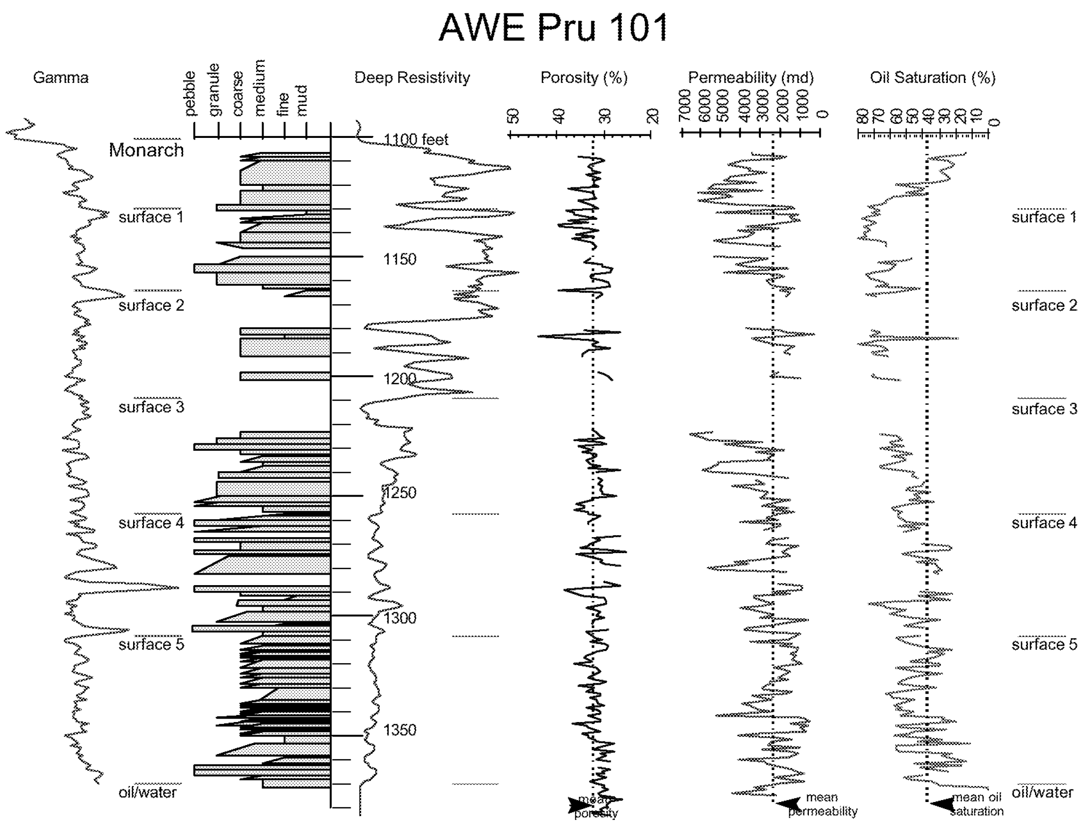

Figure 3-3: Data from the Pru-101 test well: lithology with gamma and deep resistivity logs, and porosity, permeability and So measured in 246 core samples.

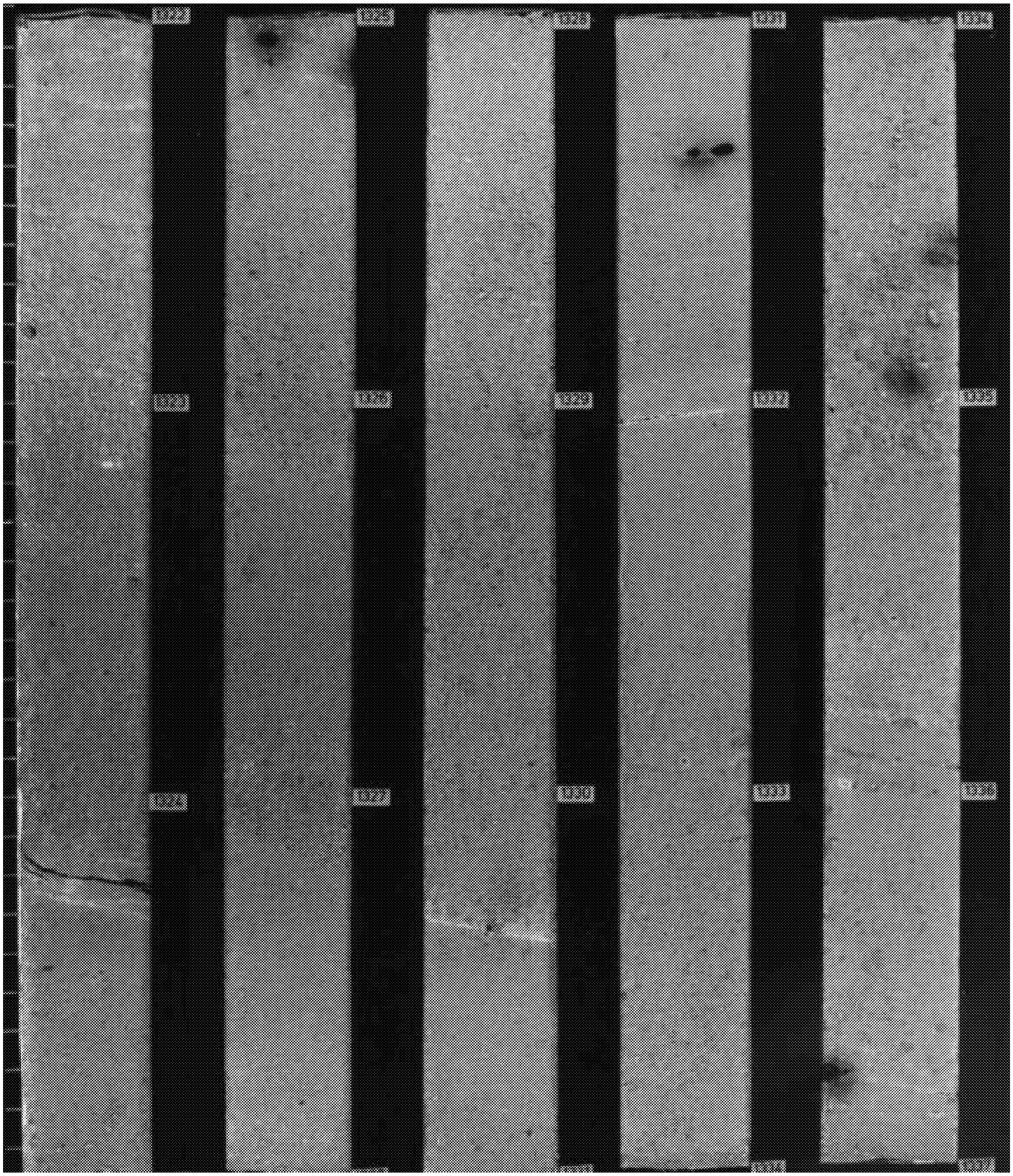

Figure 3-4: Photograph in UV light of the 1322-1337 ft interval of the Pru-101 core. This interval is characteristic of most of the sediment recovered. The sands are amalgamated with many sand-on-sand contacts, no distinct grading and few very thin diatomite-silt lenses. Floating pebbles are common.

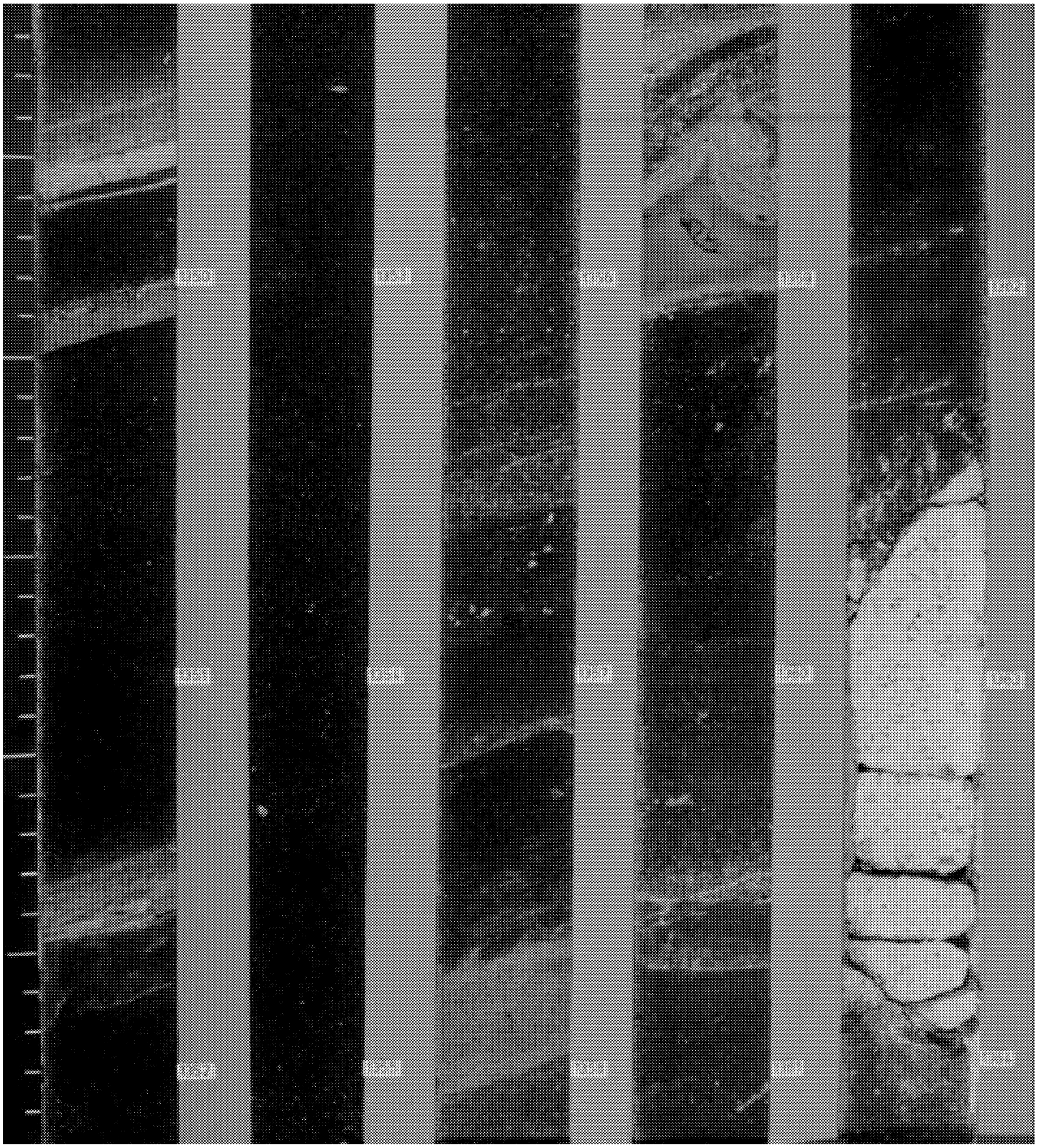

Figure 3-5: Photograph in plain light of the 1350-1364 ft interval of the Pru-101 core. This interval is characteristic of the more heterogeneous sections of the Monarch Sand in which there are numerous diatomite silt lenses, crude grading within the sands, flame structures and other indicators of intraformational defromation. There is also a granite bolder at least 18 in in diameter embedded in a pebbly sand. The sands are oil saturated.

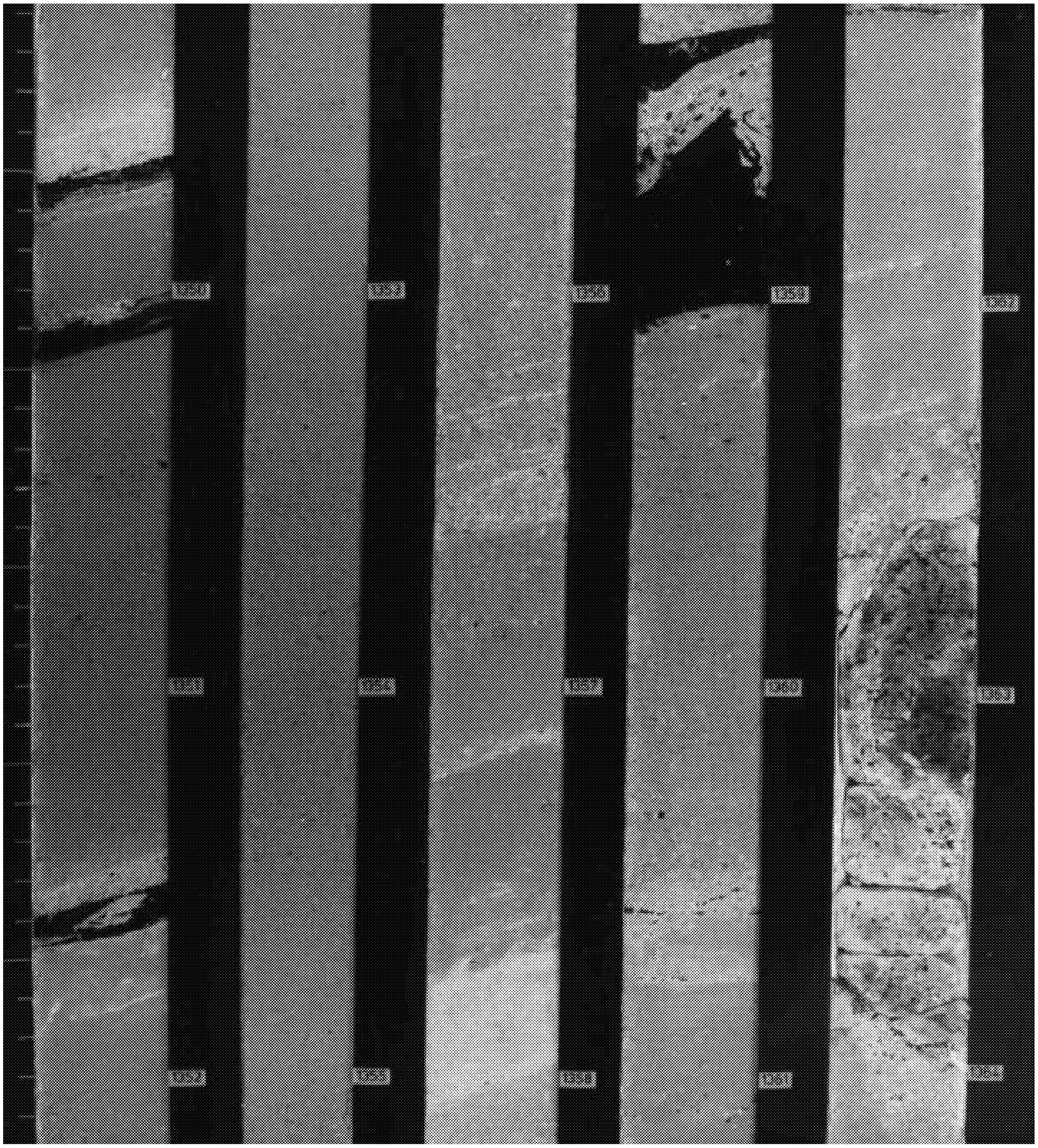

Figure 3-6: Photograph in UV light of the 1350-1364 ft interval of the Pru-101 core. Many features not visible in plain light stand out clearly in UV. In particular not the variability in oil saturation of the sands related to differences in sand texture (more intense red is higher So). The diatomite-silt intervals that are light gray in plain light (Fig. 3-5) contain no oil and are black in the UV photographs.

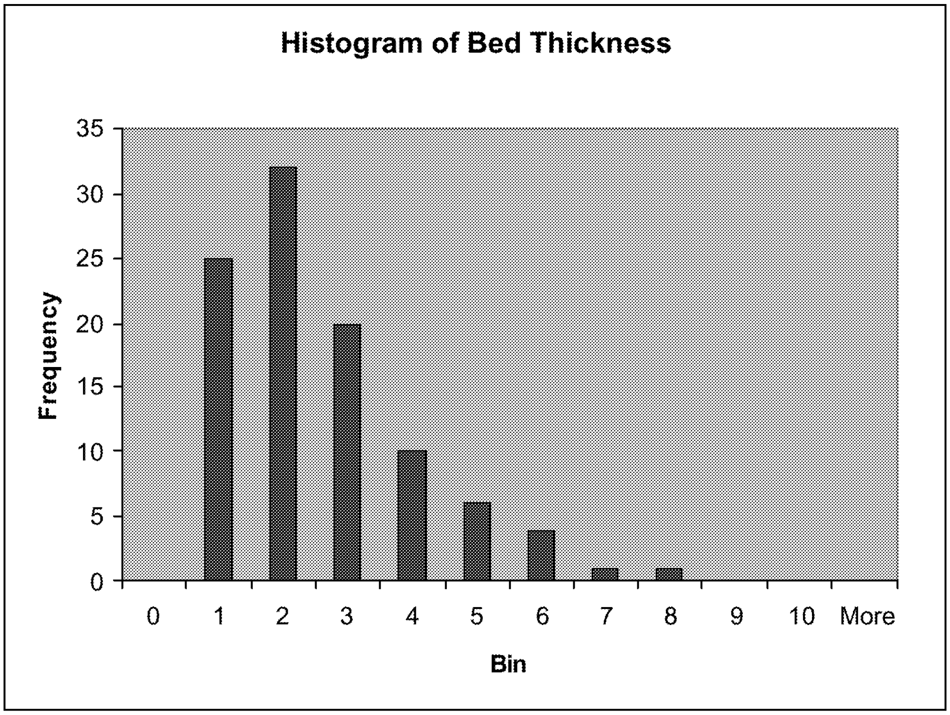

Figure 3-7: Histogram of bed thickness measured in the Pru-101 core.

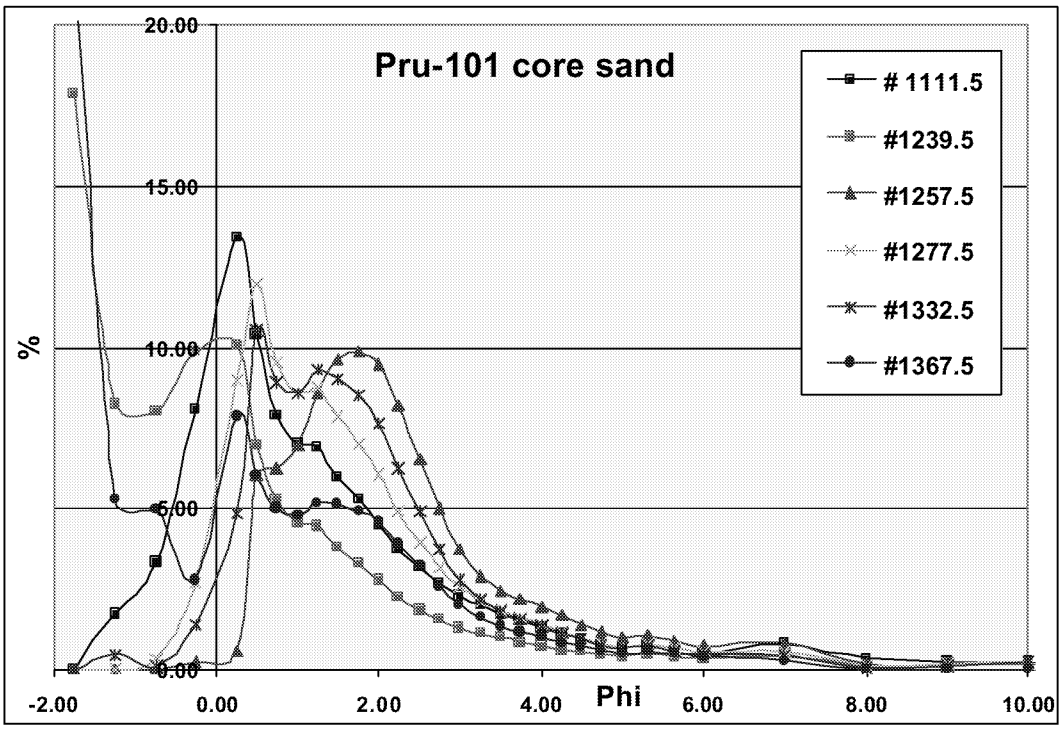

Figure 3-8: Sand size frequency distribution for six core samples of different lithotype. See text for explanation.

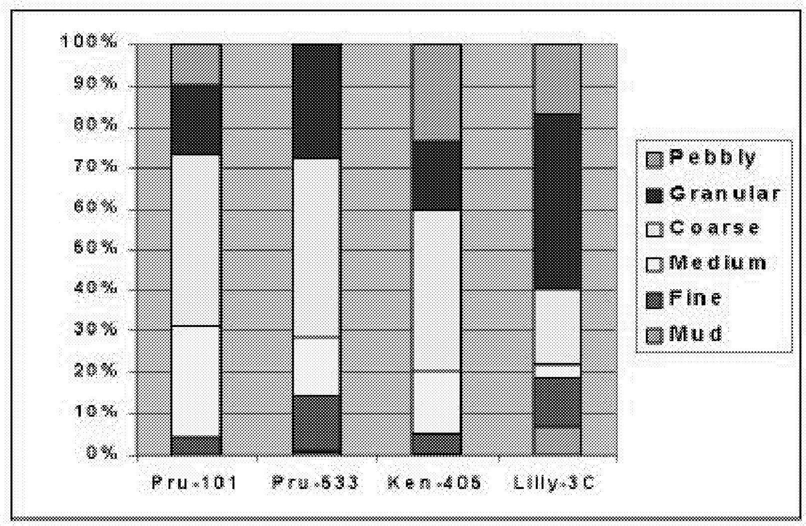

Figure 3-9: Relative portions of different lithofacies principally distinguished by grain-size in Pru-101 core and Monarch Sand core from three nearby wells. Granular and coarse sands are the dominate Monarch Sand lithologies at all four sites.

Figure 3-10: Crocker Canyon Sand exposed in Crocker Canyon at the north end of the Midway-Sunset field. This is a massive sand unit with a few thin discontinuous diatomite-silt lenses (resistant beds). The sand body is encased in diatomite seen in the far end of the outcrop.

Figure 3-11: Thinly laminated diatomite-siltstone overlying the top of the Crocker Canyon Sand. Note the repeated sand -on-sand contacts that constitute the bedding within the sand body.

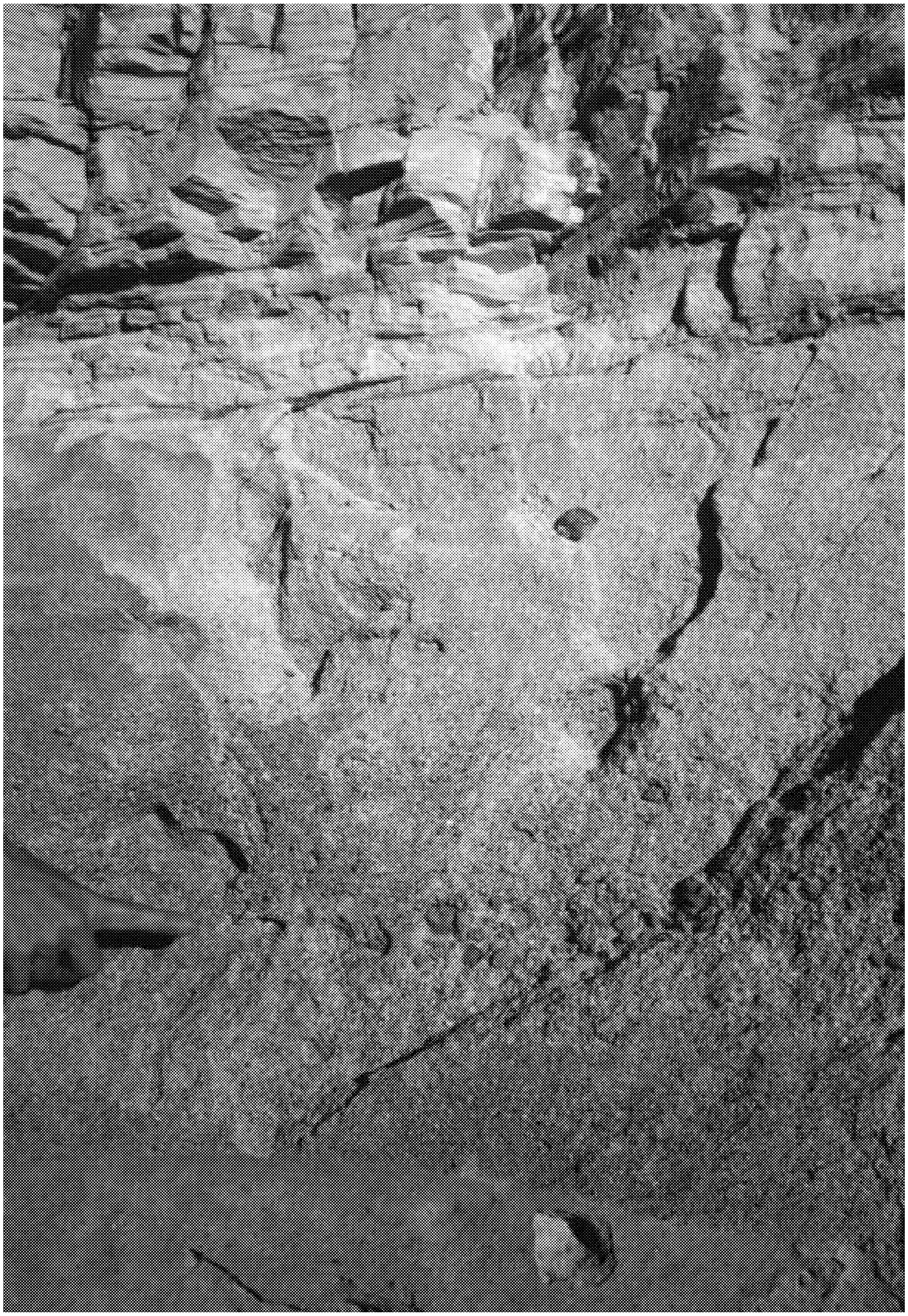

Figure 3-12: Detail of the sand-on-sand contacts that dominate the Crocker Canyon Sand body. The hand points to and interval of diatomite rip-up clasts within a granular sand. There are also clasts floating in finer-grained sands. Thinly laminated diatomite is seen at the top of the photograph.

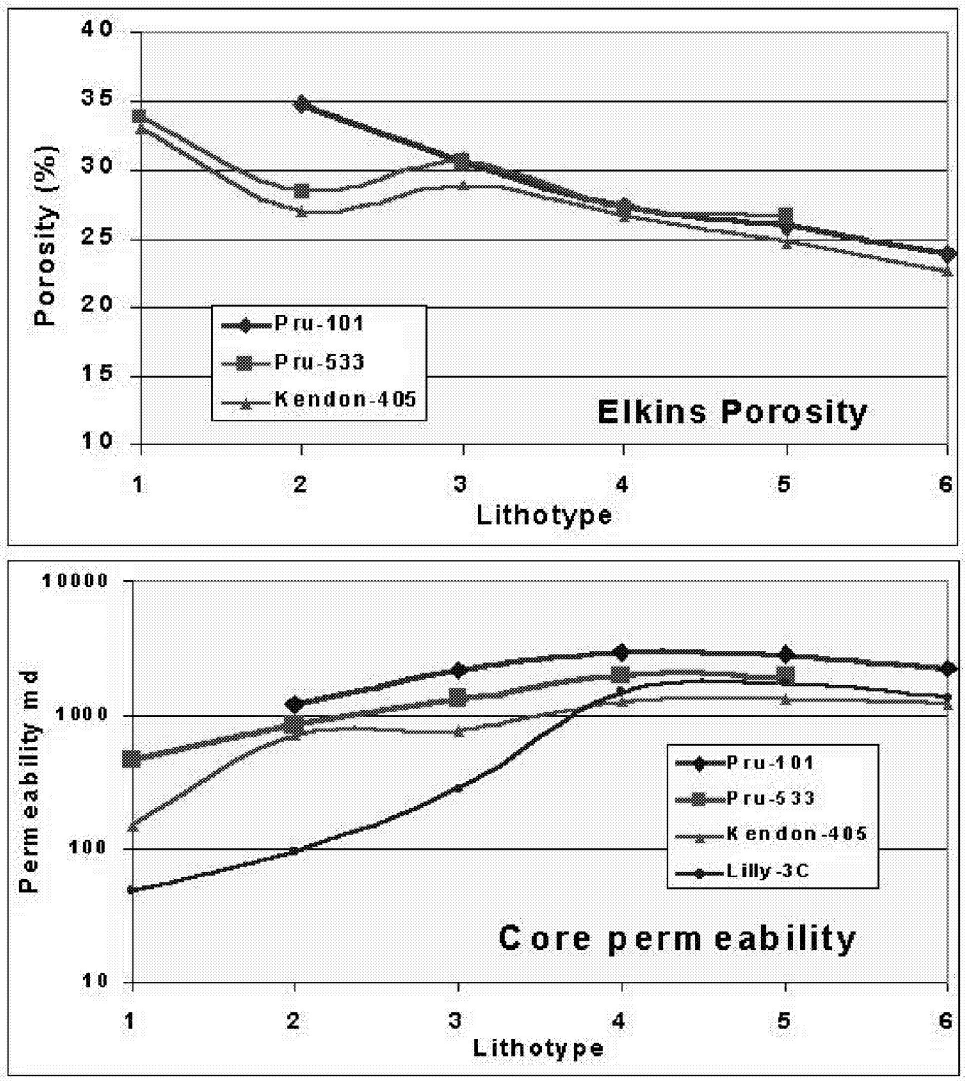

Figure 3-13: Porosity and permeability vary with lithofacies. The values plotted are group averages. The lithofacies are: 1=mudstone, 2=fine sand, 3=medium sand, 4=coarse sand, 5=granular sand, 6=pebbly sand. Note that porosity increases in the finer grain sizes, especially in the diatomite (mudstone). The lithofacies having the larger permeability are the coarse and granular sands.

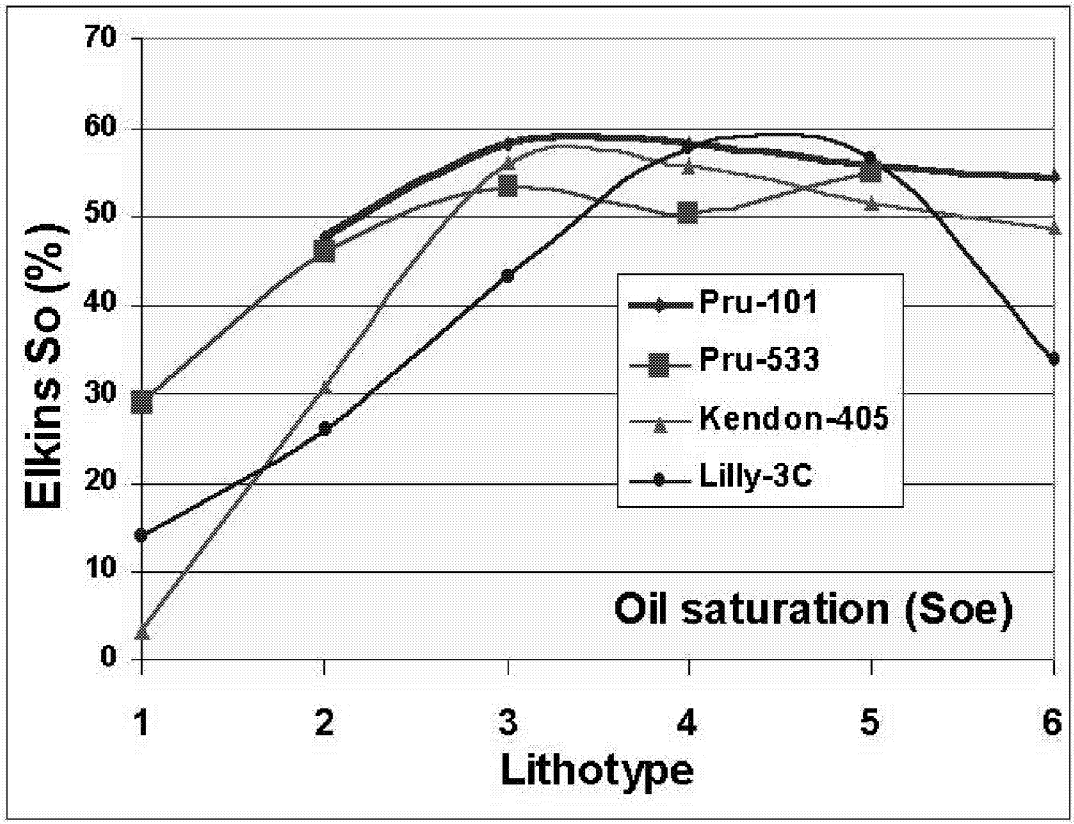

Figure 3-14: Oil saturations vary with lithotype being relatively higher in medium to granular sands than in fine sand and mudstone, or even pebbly sands.

Stratigraphic Model

General Statement

Heavy oil production at the Pru Fee property is from the upper Miocene Monarch Sand, part of the Belridge Diatomite Member of the Monterey Formation (Fig.3-15). The pay interval is just 1100-1400 ft deep. Like other sand bodies within the Monterey Formation, it is a deep submarine channel or proximal fan deposit encased in diatomaceous mudstone. The sand is derived from an elevated portion of the Salinas block, which during the late Miocene lay immediately to the west of the San Andreas fault just 15 miles to the west of the site. The top of the Monarch Sand, actually a Pliocene/Miocene unconformity, dips at less than 10° to the southwest off of the eastern flank of the Temblor Range. The unconformity bevels downward at a very low angle to the northwest across the upper portion of the Monarch Sand body. The net pay zone, which averages 220 ft at Pru Fee, thins to the southeast as the top of the sand dips through the nearly horizontal oil-water contact (OWC). In the southeast half of the Pru property a thin wedge of Belridge Diatomite overlies the Monarch Sand beneath the Pliocene/Miocene unconformity providing a somewhat more effective steam barrier than the Pliocene Etchegoin Formation, a silty, sandy mudstone.

The only other oil-bearing unit at the Pru Fee property is the Tulare Formation (Fig. 3-15), Pliocene interbedded fluvial sands and shales at a depth of about 500 ft that contain an estimated 2.5 MMBO potential reserves. These additional reserves were discovered as a consequence of drilling and logging the wells for the DOE Class 3 project. Production by cyclic steaming of heavy oil from the Tulare was started in the second half of 1998 in the southern third of the Pru property.

The stratigraphic nomenclature applied to this part of the Midway-Sunset field is a combination of formal units (which are recognized at the surface and in the subsurface) and informal units, which are mostly identified in the subsurface. The stratigraphic nomenclature of Foss and Blaisdell (1968), Reid (1990), Nilsen (1996), and Sturm (1996) has been adopted in for this project as it most closely reflects that used by the petroleum industry.

The Monarch sand is one of several sand lenses within the Belridge Diatomite Member of the Monterey Formation (Fig. 3-2). It overlies the informal Republic, Williams, and Leutholtz sands (in descending order) of the Antelope Shale. The Reef Ridge Shale overlies the Monarch in other portions of the Midway-Sunset field. However, a regional Pliocene unconformity, referred to as the sub-Etchegoin unconformity (Sturm, 1996), truncates the Reef Ridge Shale and the top of the Belridge Diatomite Member at the Pru site. Here the Pliocene Etchegoin Formation rests with a low angle unconformity on the Monarch sand and an overlying Belridge Diatomite Member mudstone unit. The base of the Monarch Sand lens has not been penetrated at the Pru site. Its total thickness and relationship to underlying mudstones in the Belridge Diatomite Member are not known. However, the Monarch Sand is known to be at least 320 ft thick at the TO-2 well.

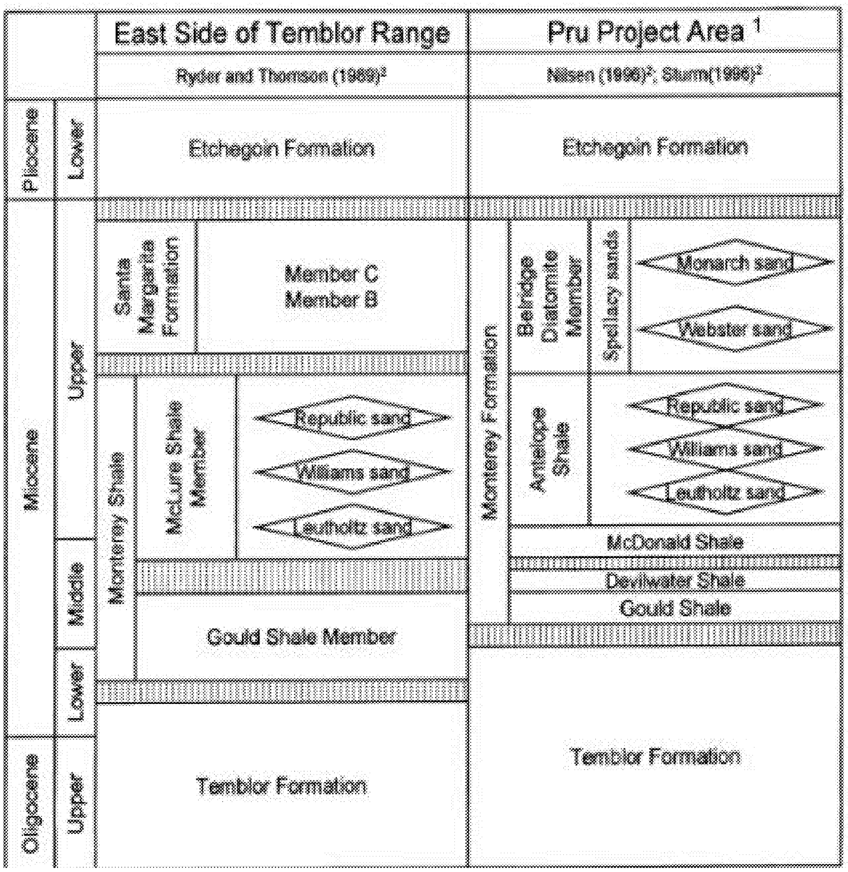

Figure 3-15: Stratigraphic table of formations in the Pru Fee project area and on the east side of the Temblor Range. The Monarch Sand is the oldest formation penetrated at the project site.

Stratigraphy of the Monarch Sand

Between October 1995 and December 1999, 40 new wells had been drilled and logged on the Pru Fee property; an additional 17 wells were drilled, but not logged. As the drilling operations had been carried out the separate stages discussed in Chapter 2, the stratigraphic model of the site was modified over the course of the project as additional well logs became available. The result was continual refinements to the initial models that better characterized the heterogeneity of the Monarch Sand and its petrophysical properties. The stratigraphic analysis was helped substantially by the existence of two wells on the Pru Fee property with nearly continuous core through the Monarch Sand. Pru-101 and Pru-533 core analyses provided the basis for calibrating log response with lithology and petrophysical properties (Fig. 3-16) and for testing the validity of log-based stratigraphic correlations. Core data from two additional wells, Kendon-405 and Lilly-3C, in adjacent properties proved useful in understanding the broader spatial variations in the Monarch Sand reservoir.

The Monarch Sand is relatively homogeneous and is dominated by thin-bedded, poorly to very poorly sorted, medium- to coarse-grained sandstone. Characteristically, medium-grained sand, coarse-grained sand, granule sand, and pebble sand are stacked in sand-on-sand bed successions. Beds are one to several ft in thickness and are to some degree graded, but not to the extent of normal turbidites. The sand packages are punctuated by lenses of diatomaceous mudstone and muddy bioturbated fine-grained sand. Cobble-size clasts (granite, gneiss and schist) up to 18 in diameter (Fig. 3-6) are observed in core and noted in logs by a high gamma spikes associated with abnormally low log porosity values. The overall lithological characteristics of the Monarch Sand are those of a proximal turbidite as described by Bouma (1962), Mutti and Ricci-Lucchi (1972; 1975), Walker and Mutti (1973), and Bouma et al. (1985). The stacking patterns, coarsening upward grain size, and a general coarse-grained nature of the highly graded beds can be interpreted as a progradational turbidite sequence (Walker, 1981).

In general, the sandy lithofacies present within the Monarch Sand alternate at a scale of a few feet or less and exhibit similar electrical log responses. This makes it virtually impossible to reliably distinguish a poorly sorted medium-grain sand from a course-grain sand. Only the two extreme lithofacies, diatomaceous mudstone and the pebbly sand, can be interpreted with any confidence from the logs. The pebbly sand lithofacies is characterized by high gamma log values, but the low-clay diatomite is not. The mudstone lithofacies consistently is associated with log porosity values greater than 35 %, whereas pebbly sands generally have log porosity values less than 26 %. In the wells for which core is not available, these two lithofacies are determined from a combination density porosity and gamma ray logs. All other intervals are merely the "sand" lithofacies undivided. Even though the wells are very closely spaced and the log suites are comparable, only the mudstone lithofacies could be correlated with any degree of reliability. The pebbly sand lithofacies is either too limited in lateral extent or too variable in log properties to be correlated as discrete layers. Only thicker mudstone intervals could be correlated between a few adjacent wells; thick mudstone intervals appear uncommon at Pru Fee.

The mudstone lithofacies, significant as a potential barrier or baffle to steamflood, was recognizable less as discrete beds that could be correlated from well to well than as a dominant lithologic element within a stratigraphic interval of limited areal extent. Only one such interval, referred to as the "Middle Marker Unit", exhibited continuity across nearly the entire pilot site. The presence of this marker unit, normally less than 15 ft in thickness, provides the only basis for dividing the Monarch Sand into subunits, in this instance three stratigraphic elements - an Upper Sand, the Middle Marker, and a Lower Sand (Figs. 3-17). Even using the full log suite, it has not been possible to realize further subdivisions of the Monarch Sand reservoir at Pru Fee. The apparent absence of lateral continuity of strata and limited variation in log responses between the various lithofacies observed in core severely limit high-resolution stratigraphic modeling of the reservoir at this site.

In the Pru-101 well the "Middle Marker Unit" mudstone interval was the only significant zone of no core recovery. The unit cannot be correlated to Pru-533 and appears to be erosionally truncated just south of this well. Thus, there was no opportunity to observe the unit in core samples to better understand its potential as a barrier (or baffle) to fluid flow and steam injection.

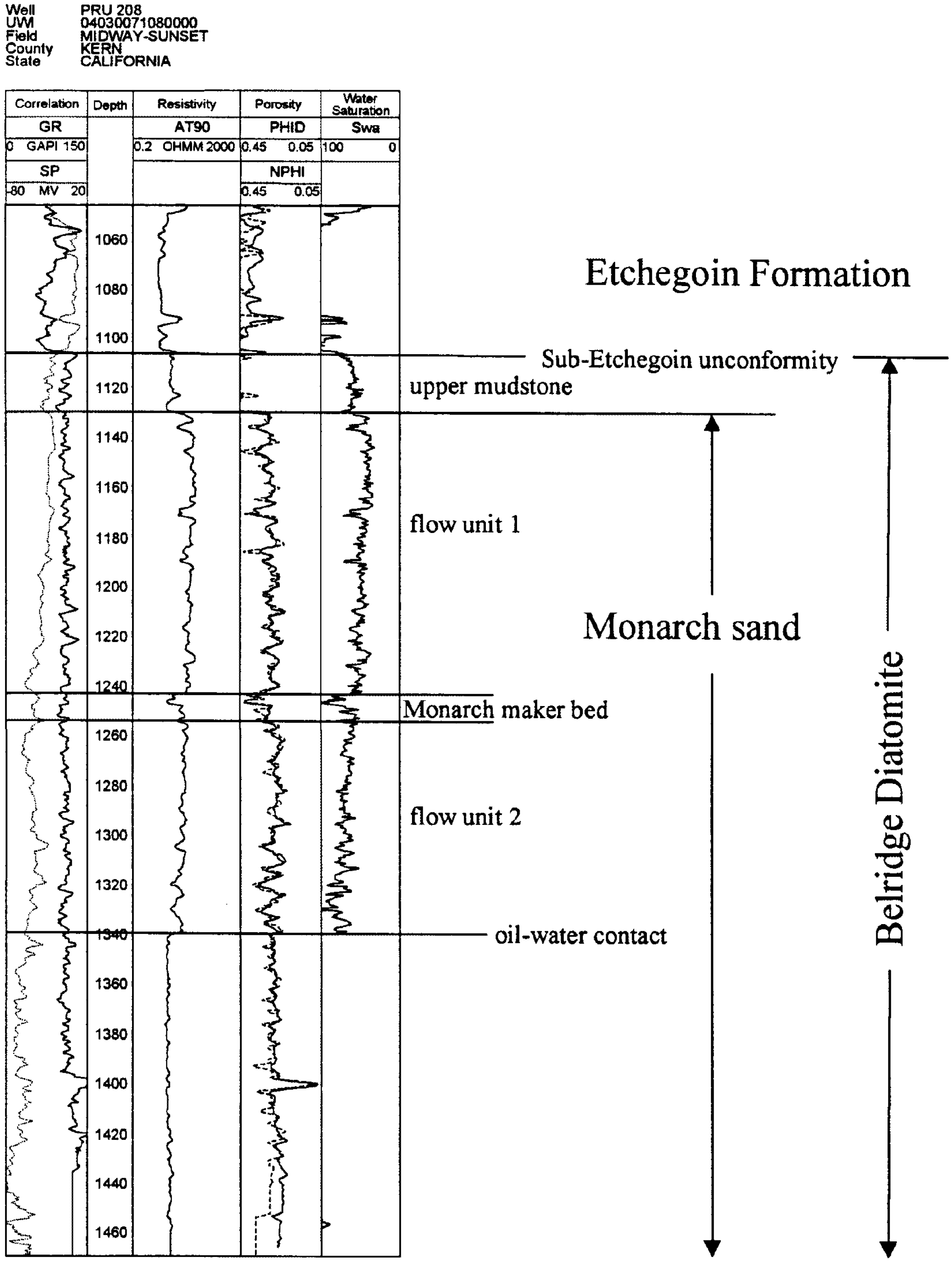

Figure 3-16: Type log of the Monarch Sand of the Belridge Diatomite Member of the Monterey Formation; Pru-208. Muddy lithofacies are interpreted as beds that have porosity greater than 35 precent. The upper mudstone is interpreted as Belridge Diatomite which depositionally overlies the Monarch Sand. This formation is probably a steam barrier. The Monarch "marke bed" is interpreted as a mudstone that is a local steam baffle.

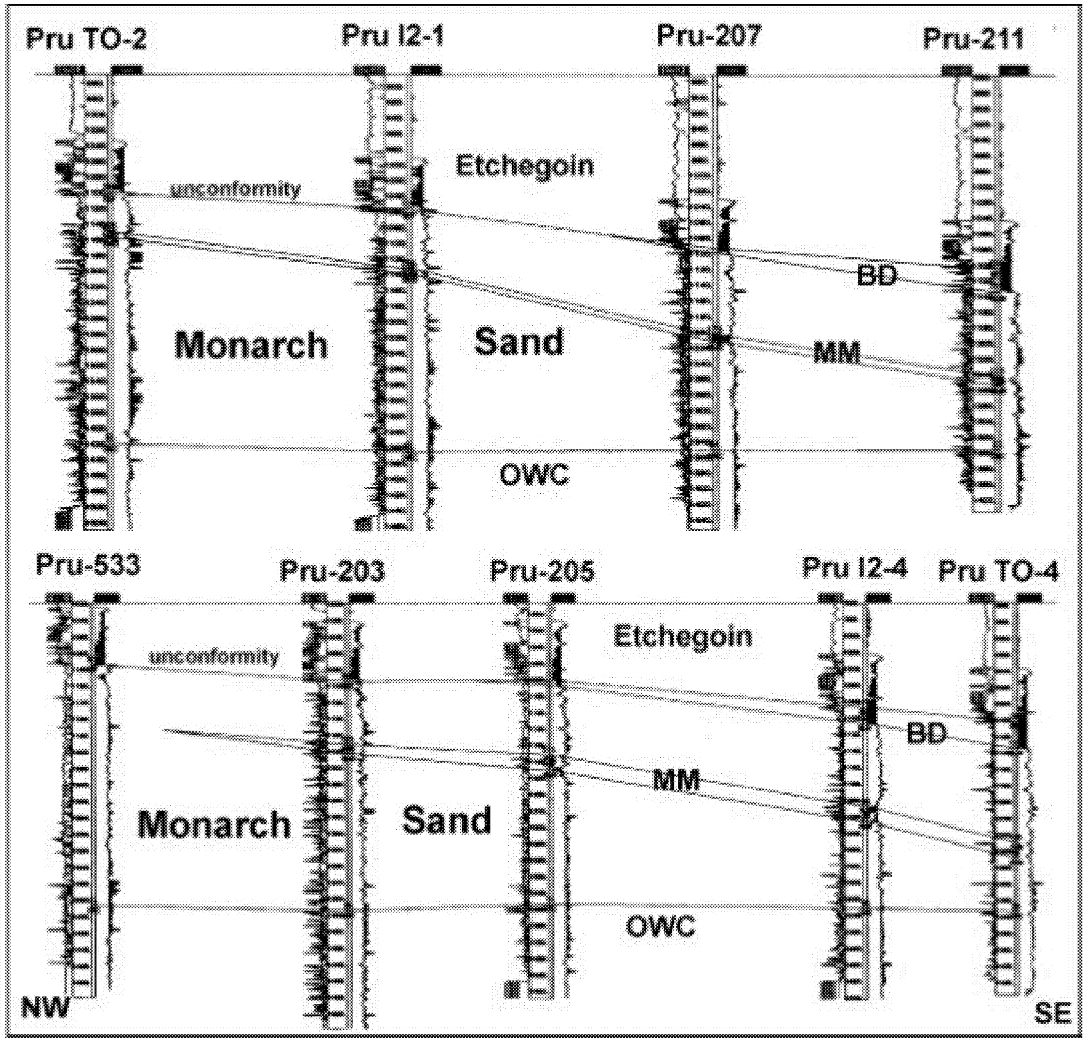

Figure 3-17: Two cross sections through the center of the Pru Fee property showing the relationship of the top Monarch Sand body to the conformably overlying Belridge Diatomite (BD) and the unconformable Pliocene Etchegoin Formation. The Monarch Sand above the oil-water contact (OWC) is divided into three subunits, an "upper sand", the "middle marker" and a "lower sand". The sections are oriented NW-SE to show the dip of strata and the upper bounding unconformity.

Even with the high density of quality log suites from the 20 wells drilled expressly for this project, it proved impossible to develop a multi-layer stratigraphic model for the Monarch Sand at this location.

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In the southeastern half of the property, the Monarch Sand is overlain by a diatomaceous mudstone, presumably the enclosing Belridge Diatomite Member, which is erosionally beveled and absent beneath the base Etchegoin unconformity towards the northwest (Fig. 3-17). This mudstone is delineated also on the basis of gamma ray and porosity log response (Figure 3-16). The Etchegoin Formation, however, is easily recognized in resistivity logs, as is the oil-water contact (OWC) within the Monarch Sand (Fig. 3-17).

Subsurface Configurations

Using the full suite of well logs available after January 2000 a set of structure contour and isopach maps were constructed to depict the subsurface configuration and elevations of key stratigraphic surfaces/uints. There are five maps important to this discussion. Figure 3-18 shows the configuration of the upper and lower bounding surfaces of the Monarch Sand pay zone. The upper surface is the base Etchegoin unconformity in the northwest half of the property and the base Belridge Diatomite in the southeast half. The base Etchegoin unconformity dips approximately 8^o SE, whereas the underlying Monarch Sand dip is slightly steeper, about 16^o SE. The sub-Etchegoin unconformity bevels northwestward across both the Belridge Diatomite mudstone above the Monarch Sand and higher portions of the "Upper Sand Unit".

The upper Belridge Diatomite mudstone is identified in wells in the southern and southeastern part of the part of the property, where it reaches a thickness in excess of 35-40ft. It is absent beneath the base Etchegoin unconformity to the northwest (Fig. 3-17). The Etchegoin Formation and Belridge Diatomite appear to be "trapping" the heavy oil within the Monarch Sand. However, with an oil density (0.98) nearly equal to that of the formation water (1.005) the quality of the trap need not be great. The two upper bounding units are considerably more significant as potential steam barriers.

The oil-water contact (Fig. 3-18) was penetrated in all of the 40 logged wells. It is generally horizontal, sub-planar surface 30 to 40 feet above sea level. The surface may be dipping very gently to the west. The scattered single-well 'cones' suggest either errors in picking the OWC in the logs or actual inverted production cones at the location of these wells.

The gross pay of the Monarch Sand (Fig. 3-19) is the oil saturated interval between the base Etchegoin unconformity and the oil-water contact (OWC) in the northwest and between the base of the Belridge Diatomite mudstone and the OWC in the southeast. There is a monotonic decrease in gross pay thickness southeastward from 380 ft in the northwest corner of the property to less than 180 ft in the southeast. On the whole the gross pay is 60-80 ft thicker than projected prior to the start of the project. Also the portions of sand in the section, 80-90%, is considerably greater than what was expected.

The "Monarch Marker Unit" (Fig. 3-20) is identified in most wells, except those in the extreme northwest where the unit is apparently cut-out by intra-Monarch erosional beveling. The surface is nearly planar, but locally the southeast dips vary slightly between 14^o and 18^o. These dips are similar to the base of the Belridge Diatomite. Although these "internal" stratal inclinations are slightly larger than what was predicted at the start of the project, they are still too shallow to sustain gravity drainage of heated heavy oil. The "middle marker" is up to 20 ft thick beneath the southern patterns in the steam flood pilot and thins outward in all directions from there. The unit tapers to a zero isopach along the northwest corner of these pilot patterns. This configuration puts a potential internal steam baffle (or barrier) beneath all of the property except patterns 9, 10, 11 and 12.

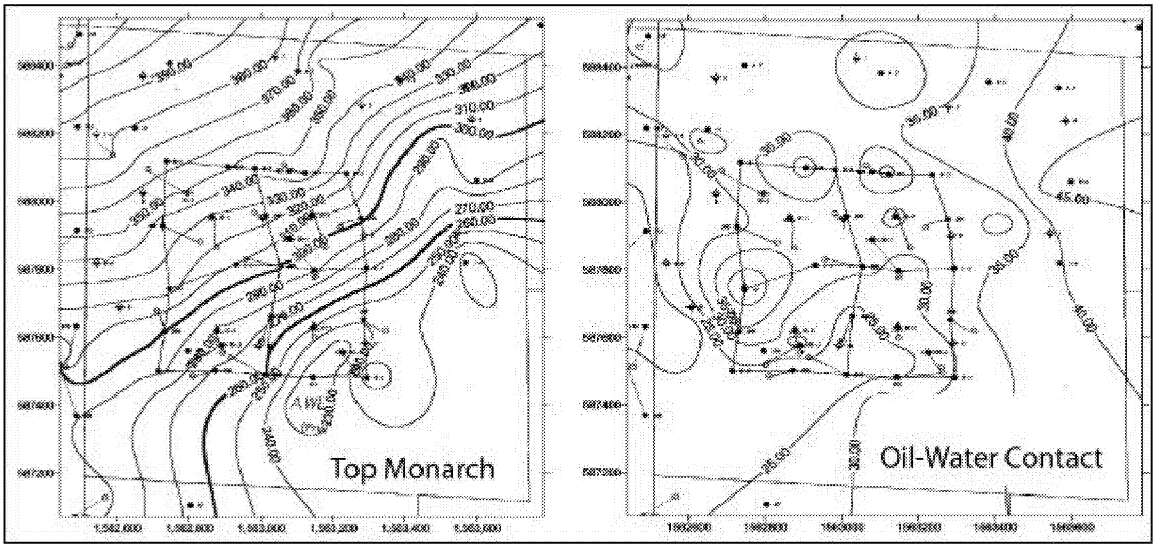


Figure 3-18: Contour maps of the two surfaces bounding the Monarch Sand pay at the Pre Fee property, the top Monarch surface (base Etchegoin unconformity in the NW half of the property) and the oil-water contact. The datum for both maps is mean-sea level (msl); the units are feet.

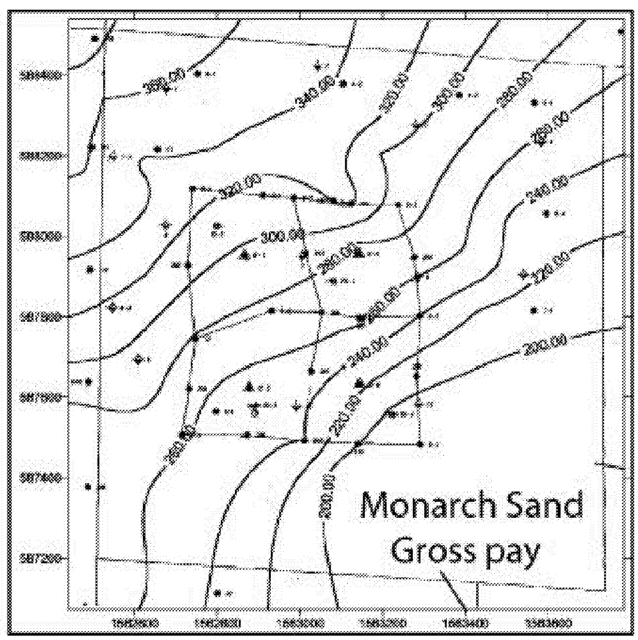


Figure 3-19: Thickness (in ft) of the Monarch Sand gross pay interval.

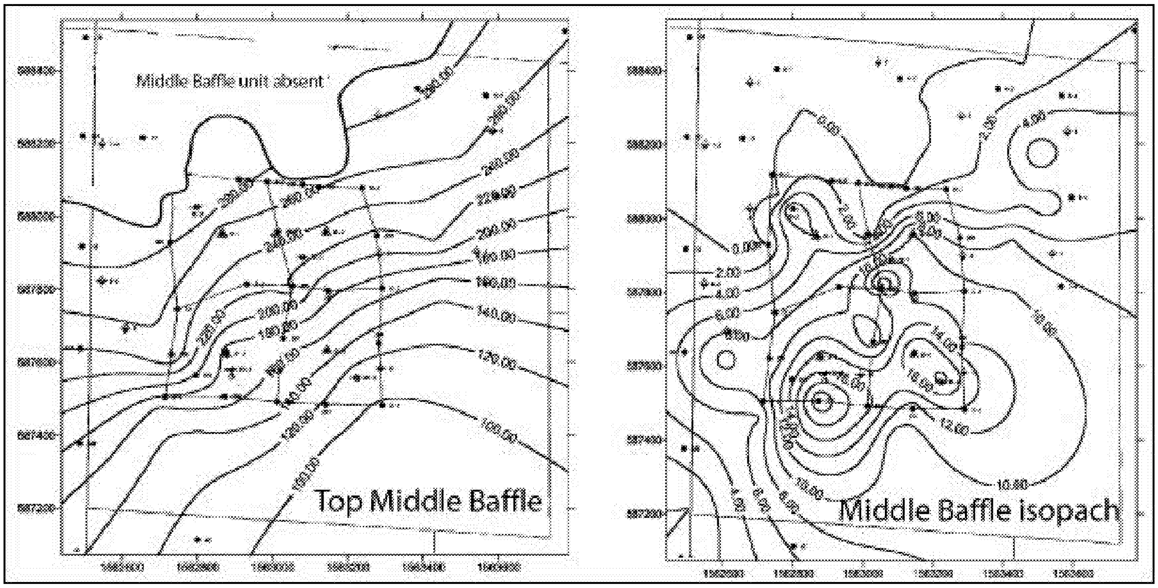


Figure 3-20: Subsurface configuration of the "Middle Baffle" or "Middle Marker" unit, a relatively thick diatomite-silt lens forming the only continuous stratigraphic marker within the Monarch Sand reservoir. The "pancake" shape of the unit has been adopted in statistical modeling of other thinner mudstone elements within the reservoir.

Fluid Compositions and Properties

Oil composition and properties

Information on the composition of the heavy oil in the Monarch Sand reservoir at Pru Fee is derived from a single oil sample collected from Pru-101 on November 1, 1995 and from eight well head oils samples taken in April 2000 (Table 3-2). The Pru-101 sample has an API gravity of 12.6 @ 60° F; the other oil samples range in API gravity from 11.2 to 14.4. Gas chromatograms of these oils (Fig. 3-21) suggest a modest degree of water washing and/or biodegradation as these oils have lost a substantial portion of their saturates. In the heavier of the oils (API < 12) the aromatic fraction is nearly twice as abundant as the saturates (Table 3-2; Fig. 3-22). In the lighter oils (API > 14) the aromatic fraction is lower and the saturate fraction is somewhat higher. The portion of NSO's in all oils is about 25%.

It is observed that API gravity of the oils varies with the oil temperature measured at the well head (Fig.-23). The heaviest and cooler of the oils are from wells in the southwest corner of the property, wells Pru-313B and Pru-209. This variation might be indicative of slight distillation of the oil in the thermal recovery process with the saturate fraction enriched in the oil that is flowing as the oil is heated.

Sulfur content of the oils ranges from 0.90 to 1.15 wt%, but does not exhibit any systematic variation with oil gravity or the well head temperature of the oil at the time collected.

Table 3-2

Geochemical analyses of Pru Fee crude oil samples

EGI Sample ID	Well Name	Location	Operator	Date Sampled	Comments	Relative Density(1)	API Gravity(1)	Wt. % Sulfur(2)	Wt. % Sulfur(3)	Wt. % Topping Loss(4)	Wt. % Asphaltene(5)
CA001C	PRU 204	Well Head	K. O'Neil	4/26/00	206°F	0.983	11.9	0.91		12.3	7.1
CA002C	PRU 207	Well Head	K. O'Neil	4/26/00	202°F - Cooler	0.976	12.9	0.90		10.1	6.5
CA003C	PRU 334	Well Head	K. O'Neil	4/26/00	220°F	0.976	12.9	1.15	1.07	3.0	6.7
CA004C	PRU 209	Well Head	K. O'Neil	4/26/00	163°F - Cooler	0.987	11.3	0.90		8.9	7.4
CA005C	PRU 205	Well Head	K. O'Neil	4/26/00	212°F	0.980	12.4	1.00		9.9	6.9
CA006C	PRU 203	Well Head	K. O'Neil	4/26/00	222°F	0.966	14.4	1.11		8.4	7.0
CA007C	PRU C2	Well Head	K. O'Neil	4/26/00	220°F	0.966	14.4	0.91	0.97	9.0	6.7
CA008C	PRU 313B	Well Head	K. O'Neil	4/26/00	132°F - Cooler	0.988	11.2	1.02		7.8	7.9

	Liquid Column Chromatography(6)			
Well Name	Wt. % Saturate	Wt. % Aromatic	Wt. % NSO	Wt. % Non Recovered
PRU 204	30.2	42.9	24.9	2.0
PRU 207	30.4	41.0	24.5	4.1
PRU 334	29.6	41.6	26.4	2.3
PRU 209	26.9	44.9	25.1	3.1
PRU 205	31.2	41.2	24.5	3.1
PRU 203	31.4	41.4	26.5	0.7
PRU C2	33.0	38.1	22.3	6.6
PRU 313B	27.4	45.0	27.4	0.2

(1) Emulsions
(2) Performed by Humble Geochemical Services, Humble, TX.
(3) Performed by Petroleum Research Center (PERC), University of Utah.
(4) Samples were held at 60°C for 24 hours.
(5) Procedurally defined as pentane insoluble.
(6) Liquid Column Chromatography performed on topped de-asphalted oil.

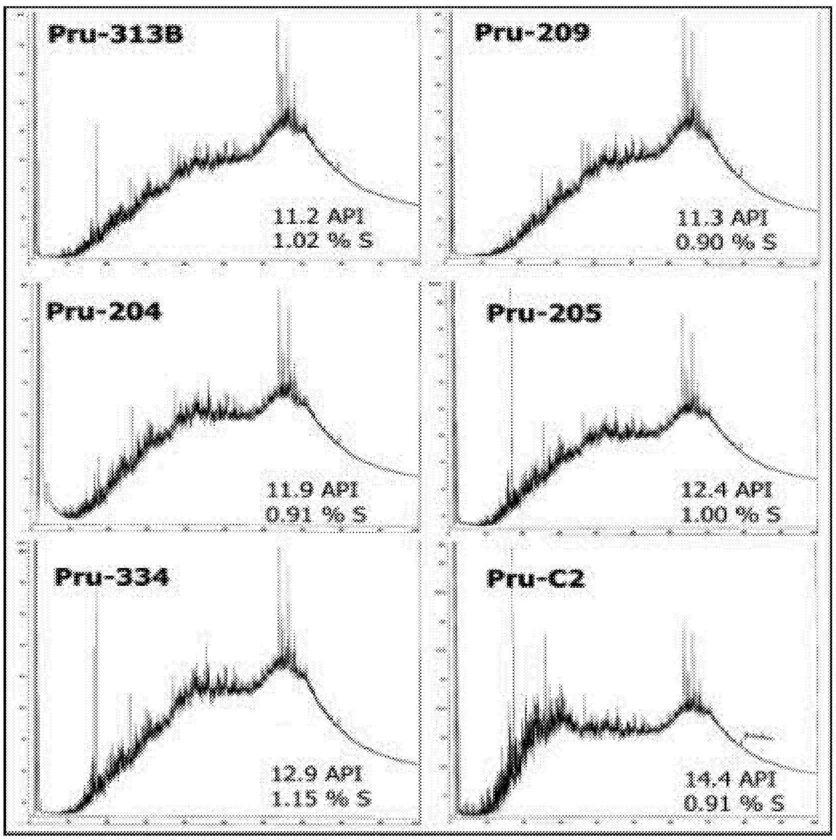


Figure 3-21: Gas chromatograms of crude heavy oil from the Monarch Sand at the Pru Fee property. The oils are arranged by API gravity from heaviest in the upper left to lightest in the lower right.

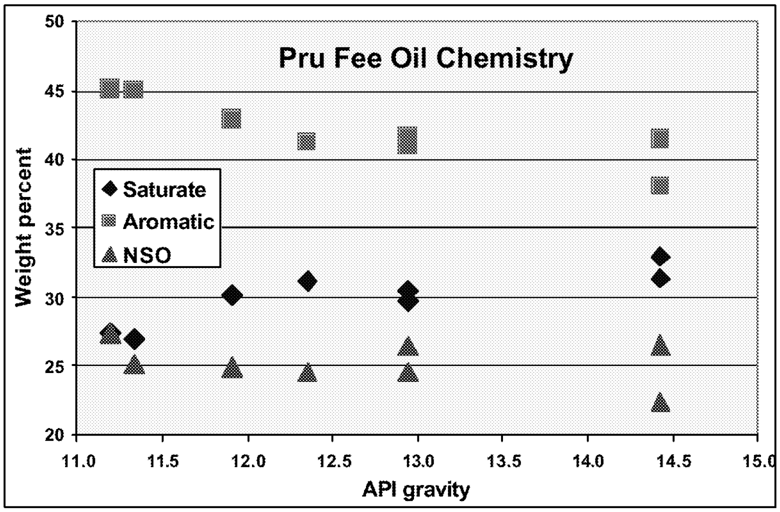


Figure 3-22: Variations in oil composition with API gravity. The heavier oils have higher aromatic fractions and relatively low saturate fractions. The NSO fraction does not vary with oil gravity.

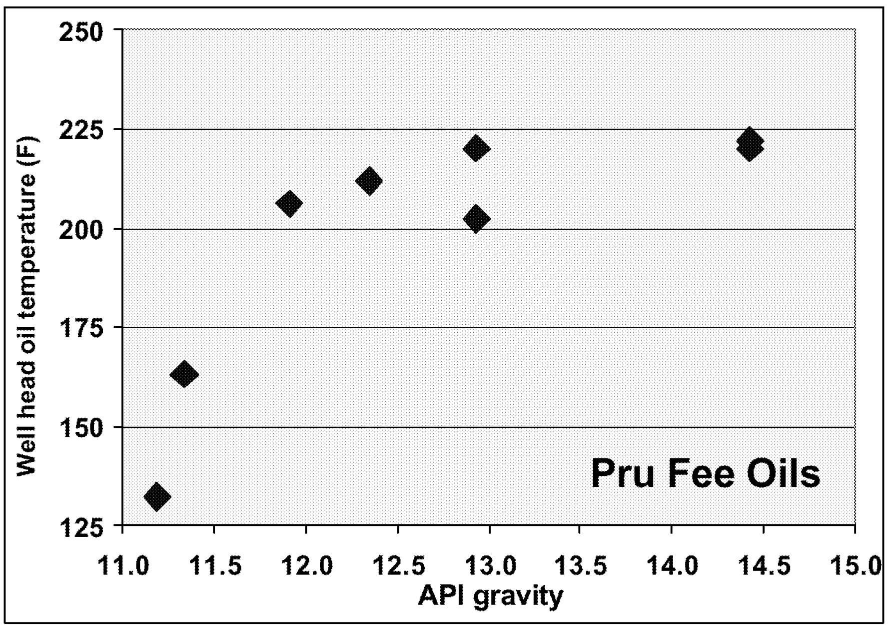


Figure 3-23: Variation in Pru Fee oil gravity with oil temperature measured at the well head at the time of sampling. The variations suggest modest distillation associated with the thermal recovery process.

Oil viscosity over a range of temperatures was measured in the single Pru-101 oil extract and in three additional oil extracts from the Lilly C-5 core (Table 3-3). The Lilly C-5 well in the Monarch Sand is located just 200 ft south of the Pru Fee property, so it is sampling essentially the same oil as that in the study area. The API gravity is in the range 11.2-12.3, comparable to the Pru-101 oil gravity of 12.6 API. Viscosity was measured by a Cone and Plate Viscometer.

The values of viscosity range from 1754 cp @ 100° F to 38 cp @ 225° F (Table 3-3). The slightly heavier Lilly C-5 oils are also slightly more viscous (Fig. 3-24), but the viscosity-temperature trend lines are parallel. The equation for the exponential best-fit curve to the four Pru-101 viscosity values is shown in Figure 3-24. Thus, the predicted viscosity of oil in the Monarch Sand under current thermal recovery reservoir temperatures of 225° to 350° F is in the range 21.5 cp to 1.1 cp. The viscosity at 300° F is about 3.2 cp.

Table 3-3: Measured viscosity in oil extracts from Pru-101 and Lilly C-5 wells

Temp (F)	1/T (K)	Pru-101	C-5:1211'	C-5:1213'	C-5:1364'
API		12.6	12.3	12.3	11.2
100	0.003216	1754 cp			
122	0.003095		873 cp	1296 cp	1741 cp
140	0.003002	285.9 cp			
175	0.002836		137 cp	162 cp	192 cp
180	0.002814	79.8 cp			
200	0.002729	51.2 cp			
225	0.002629		38 cp	41 cp	47 cp

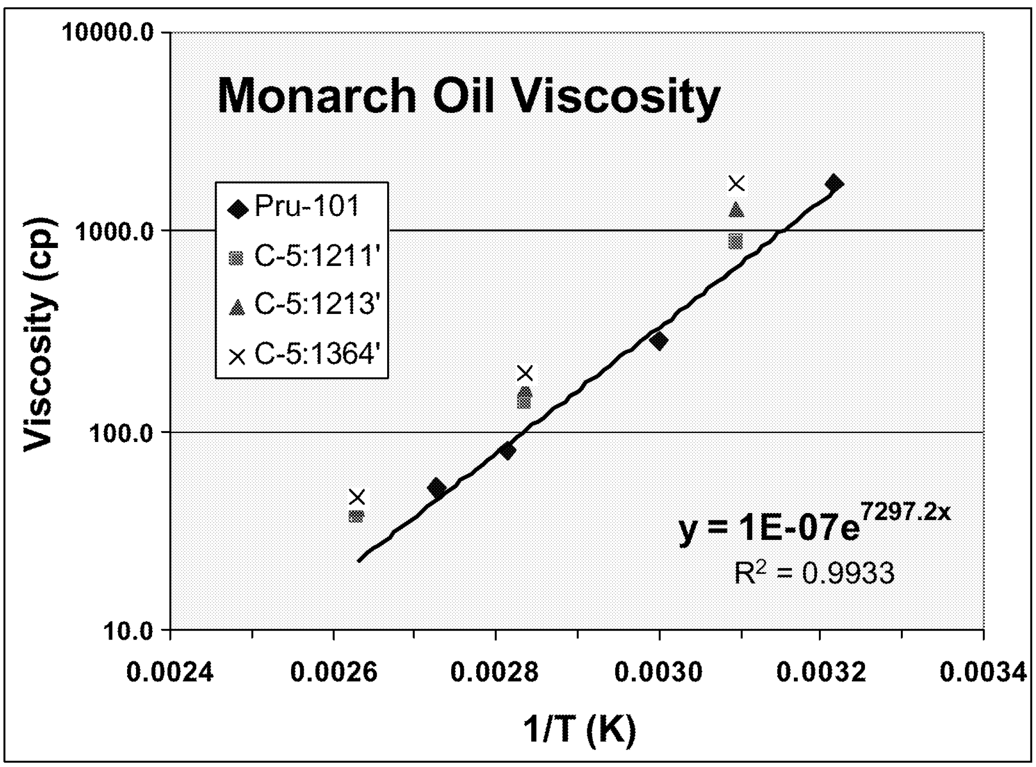


Figure 3-24: Plot of measured viscosity against temperature expressed as the inverse of degrees Kelvin, a convenient way of describing change in viscosity as a function of temperature. Data are from Table 3-xx. The best-fit exponential curve is for the four Pru-101 oil measurements.

Formation water

The formation water in the Monarch Sand reservoir is brackish, probably meteoric, water that is part of an unconfined aquifer system in the uppermost Miocene strata of the shallower parts of the Midway-Sunset field. Water samples were collected on November 1, 1995 from the newly drilled Pru-101 well and on April 21, 1997 from the Pru-205, Pru-207, Pru-208, Pru-209, Pru-210 and Pru-211 wells. The essential chemical characteristics of these waters are presented in Table 3-4. With total dissolved solids in the range 5,600 to 9,000 mg/l the waters are slightly brackish. These values are at least one or two orders of magnitude less than that measured in formation waters of deeper, more conventional, oil fields (Chilingarian et al., 1994). However, the values are too high to meet standards (Walton, 1970) for high-pressure boiler feed water (<1,500 mg/l) and drinking water (<500 mg/l). The high pH in the range 8.2-8.3 is consistent with the high total alkalinity in the range 1,000 to 3,300 mg/l. These waters are buffered against calcium carbonate. The water compositions are typical of ground waters in arid environments, such as the western margin of the San Joaquin Basin.

Table 3-4: Chemical characteristics of Pru Fee formation waters

	Pru-101	Pru-208	Pru-209	Units
Specific gravity @60F	1.004	1.006	1.006	
pH	8.3	8.2	8.2	
Resistivity @ 25C	1.13	0.78	0.73	ohm-meter
Conductivity @ 25C	8.87	12.8	13.74	millimhos/cm
Total dissolved solids	5,600	8,100	9,000	mg/l
Total sodium chloride	4,800	7,100	7,600	mg/l
Total alkalinity (CaCO3)	1,800	3,300	2,900	mg/l

	Pru-205	Pru-207	Pru-210	Pru-211	Units
Specific conductance	12.7	13.1	13.7	13.9	millimhos/cm
Total dissolved solids	8,100	8,200	8,500	8,700	mg/l
Total suspended solids	na	4,700	na	na	mg/l

The relatively high resistivity (0.73-1.13 ohm-m) and low conductivity (8.9-13.9 millimhos/cm) are consistent with the low salinity (4,800-7,600 mg/l) of these formation waters (Rider, 1998).

The depth to the water table across the Pru Fee property is easily mapped using well logs. The water table is marked by a pronounced increase in resistivity. It is generally at a 200-250 ft depth below the ground surface and follows the surface topography quite closely (Fig. 3-25). The hydrostatic pressures calculated from the height of standing water above the top of the Monarch Sand (Fig. 3-25) is in the range 370 to 410 psi. The injectors are operating at pressures very close to, and in some instances somewhat less than, these hydrostatic pressures.

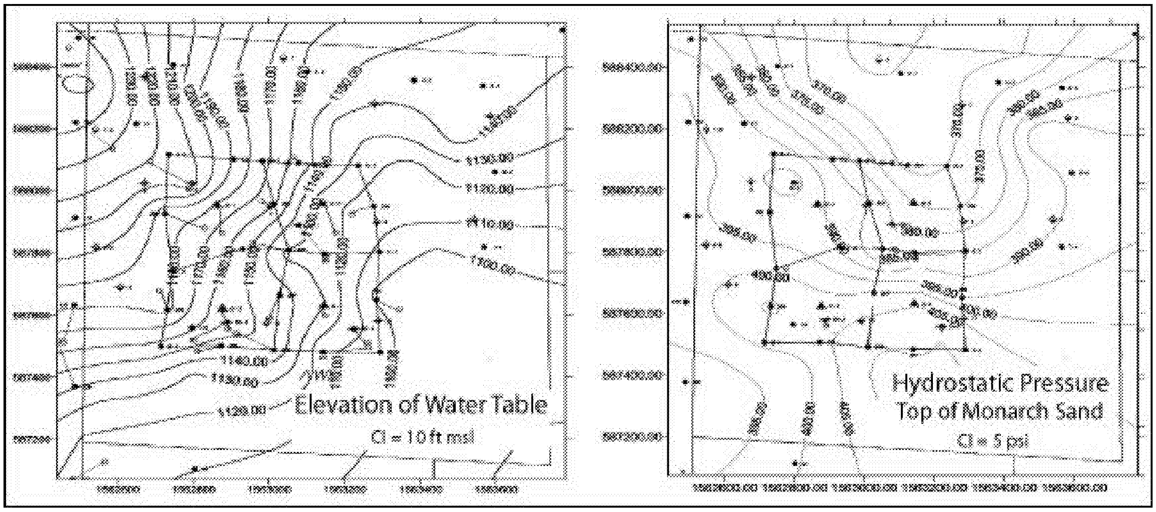


Figure 3-25: Elevation of the water table at the Pru Fee property and the calculated hydrostatic pressure at the top of the Monarch Sand reservoir.

Fluid Saturation in the Monarch Sand Reservoir

Spatial variations in fluid saturation are recognized as the most critical petrophysical parameter for efficient management of production from the Monarch Sand reservoir. The large number of well logs eventually taken at this property has permitted a very detailed analysis of oil saturations and implications for future productivity.

Vertical Variations in Oil Saturation

The vertical variation in oil saturation, represented as water saturation (Sw), is depicted for the steam flood pilot in a set of four cross sections(Figs. 3-26 through 3-29). In the sections the top of the Monarch Sand is indicated by the surfaces marked BEF and BUM. An intermediate diatomite-silt interval within the Monarch Sand, the "middle baffle", is bounded by the surfaces TMB and BMB. The bottom of the pay interval is the oil-water contact, OWC.

For each well a porosity log is on the right, showing gross variations in lithology, and a pair of calculated Sw logs is on the left. Sw is depicted with a standard Archie curve and a modified Archie curve based on petrophysical analysis of the Pru 101 core by ARCO Exploration & Production Research. The reader is referred to the first section of this chapter for a full discussion of this modified Archie equation. The modified Archie equation results in about 5% higher oil saturations (So-arco) than the standard Archie equation. In the set of cross sections the modified Archie curve stands slightly to the left of the standard Archie curve, that is, at lower values of Sw and higher values of So. The vertical and lateral variations in So are seen in the degree to which the paired curves swing upward to the left. A 50% cutoff has been added to the two Sw curves to make them easier to read.

The cross sections show that in general the So values in the upper third to upper half of the pay interval exceed 50%. The highest values of So are in the upper third of the interval. However, virtually all wells show So decreasing substantially in a "oil depletion" zone 10-30 ft thick at the very top of the Monarch Sand reservoir. The oil depletion zone is thought to be the product of earlier (pre-1995) thermal production and downward drainage of oil in the reservoir.

Reservoir simulations with geostatistically generated data sets reveals that the initial fluid distribution in the reservoir has the most significant impact on the economics of the cyclic-flooding process. The initial fluid distribution is determined by the placement of the OWC and the resulting So transition zone in the reservoir. The current approach to production involves initial steam injection within the upper third of the oil column, where So generally is greater than 60%, so as to avoid undue loss of heat to water.

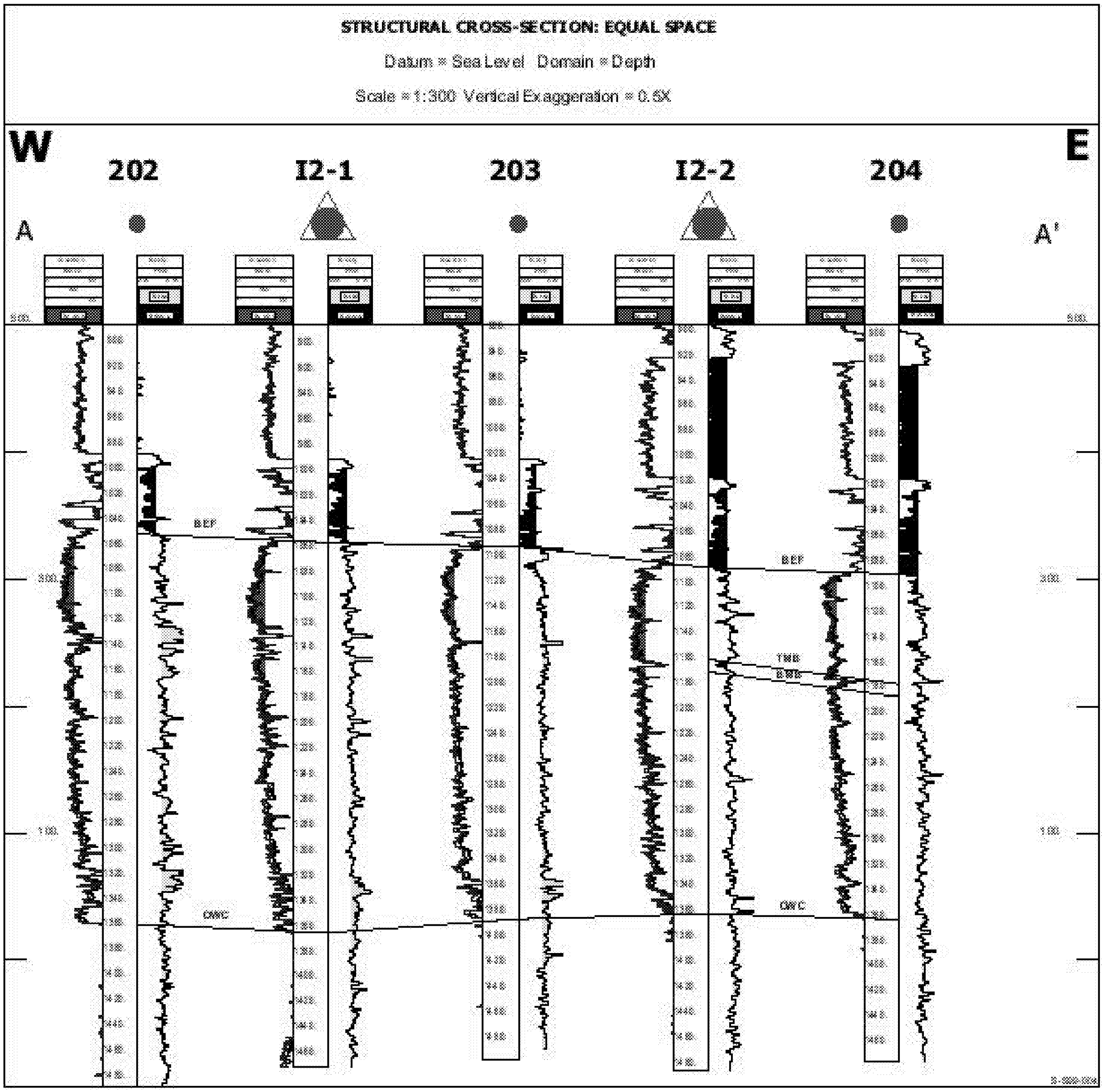


*Figure 3-26: Water saturation (**Sw**) and porosity logs for a set of wells in a west-east cross section through the northern portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

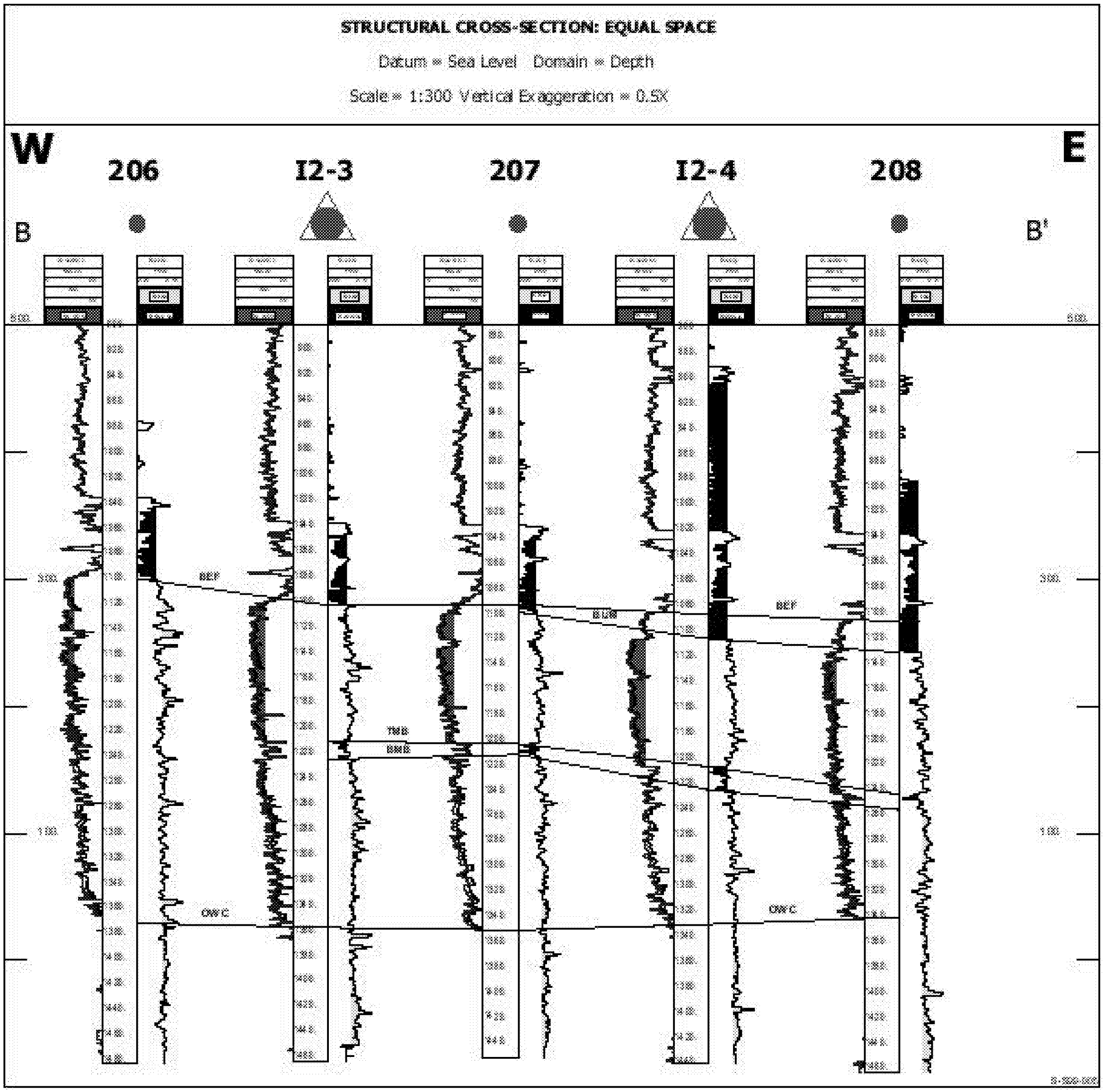


*Figure 3-27: Water saturation (**Sw**) and porosity logs for a set of wells in a west-east cross section through the southern portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

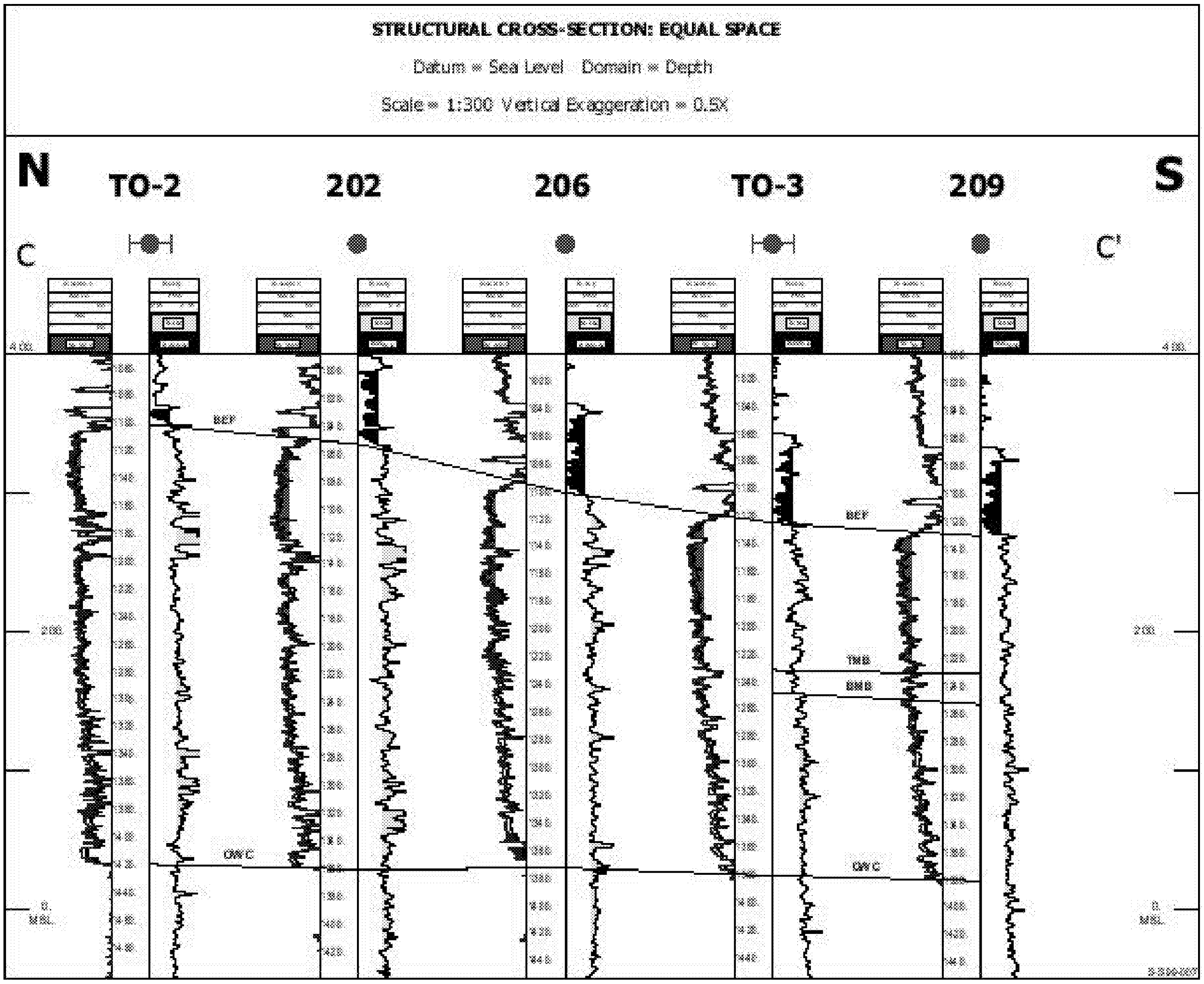


*Figure 3-29: Water saturation (**Sw**) and porosity logs for a set of wells in a north-south cross section through the western portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

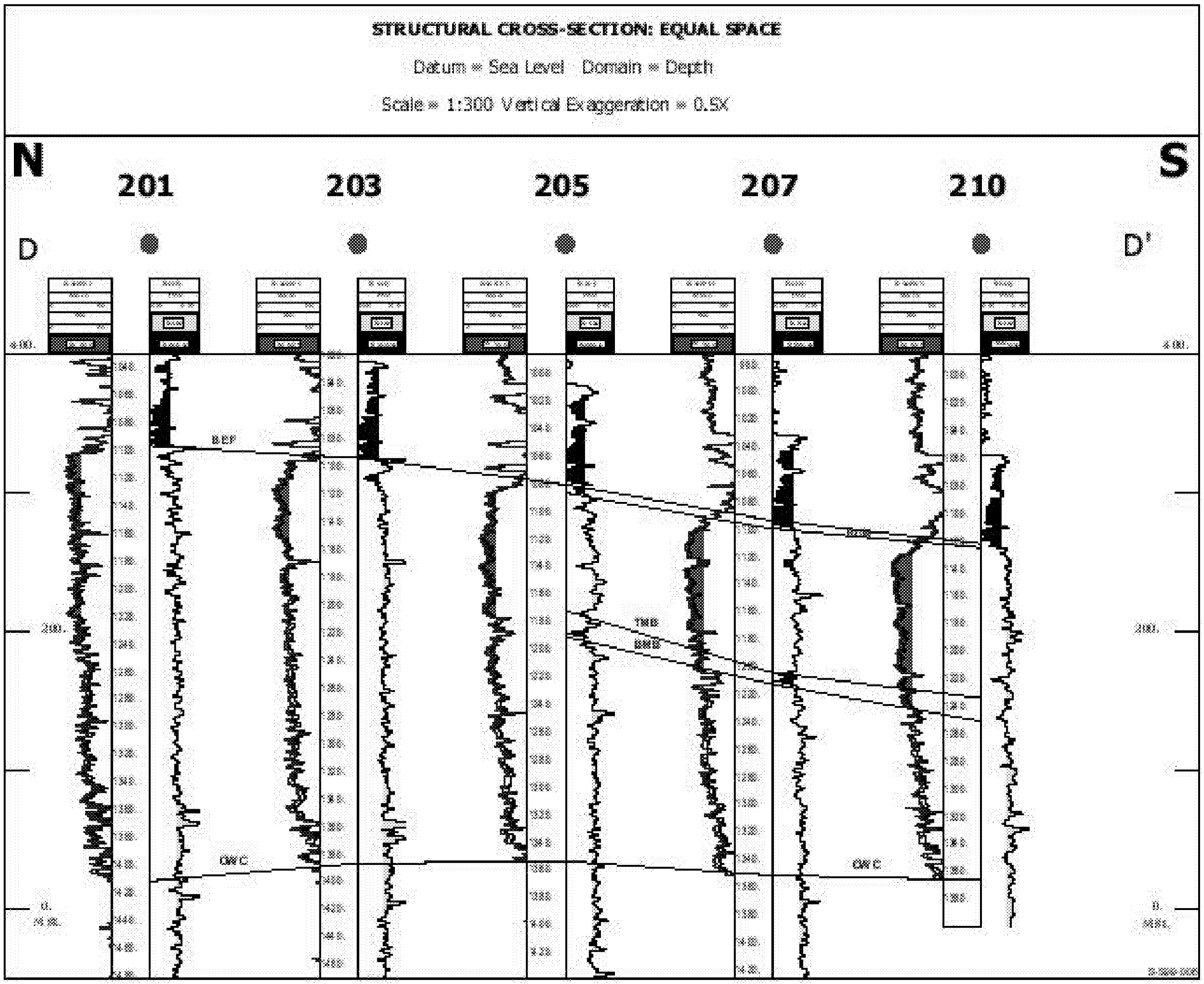


*Figure 3-30: Water saturation (**Sw**) and porosity logs for a set of wells in a north-south cross section through the eastern portion of the Pru steam flood pilot. Note the gradual decrease in **Sw** (increase in **So**) upward through the oil-saturated interval above the OWC.*

Mapping fluid saturation in the reservoir

The strategy for completion of the four injector wells in the Pru Fee pilot was strongly influenced by the water saturation (Sw) profile observed in the Pru-101 test well (Fig. 3-31) drilled and cored as part of the feasibility study for the project. The Sw profiles are derived from log data using the ARCO-modified version of the Archie equation as described above. The calculations were done within Prizm®. The Pro-101 profile exhibits a progressive upward decrease in Sw over a span of about 125 ft from values in the 80-90% range immediately above the oil-water contact (OWC). Relatively stable Sw values of 25-30% are observed in a 150 ft thick interval in the upper half of the well. The uppermost 30 ft of the Monarch Sand, referred to in earlier reports as the "oil depleted zone" again had high Sw values. The strategy followed in completing the pilot injectors involved placing the six perforations per well in a 60-80 ft interval near the lower part of the zone of lowest Sw. A standoff of 130-200 ft for the injection interval was maintained from the OWC; standoff from the top of the Monarch Sand reservoir was 40-50 ft (Table 2-**xx**).

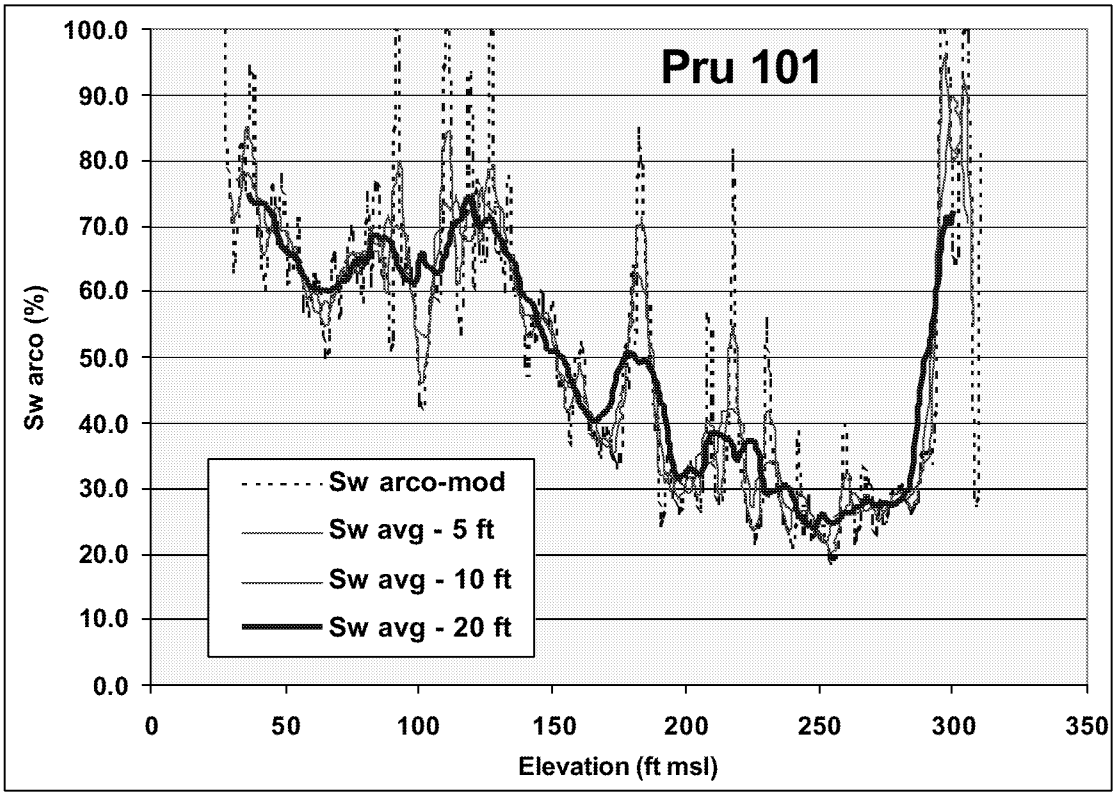


Figure 3-31: Sw values in the Monarch Sand reservoir calculated from the Pru-101 well log plotted by elevation msl. The fitted curves are the 5 ft, 10 ft and 20ft moving average for So values plotted in the dotted curve.

The thirteen additional wells drilled by Aera Energy LLC in converting the "300-series" cyclic wells to steam flood provided valuable data for assessing water saturation (Sw) distributions in the Monarch Sand across most of the property. The new wells show extreme variations in Sw not previously recognized. Less extreme variations observed earlier in several of the "300-series" wells where thought to be a consequence of poor quality log data. The Sw vertical profile is definitely not uniform from one small portion of the property to the next, as sampled by the array of the 40 new wells logged during this demonstration project. However, certain areas exhibit larger variation from the "ideal" Sw curve than others.

In contrast to the Pru-101 Sw profile, many other logs have nearly constant Sw values throughout their length, varying little from the 50-60% range (Fig. 3-32). A few profiles exhibit bizarre configurations in which the entire upper half, or even middle half (Fig. 3-33), of the Monarch pay interval has values of Sw very close to 100%. One also will notice in these figures that within any short interval the variation in Sw values can be very large. There is a half-foot resolution to the calculated Sw values, which is about the same as of just slightly less than bed thickness throughout much of the Monarch Sand. The sand texture of discrete beds or parts of graded beds appears to have some degree of control on the fluid saturations, leading to the high vertical variability.

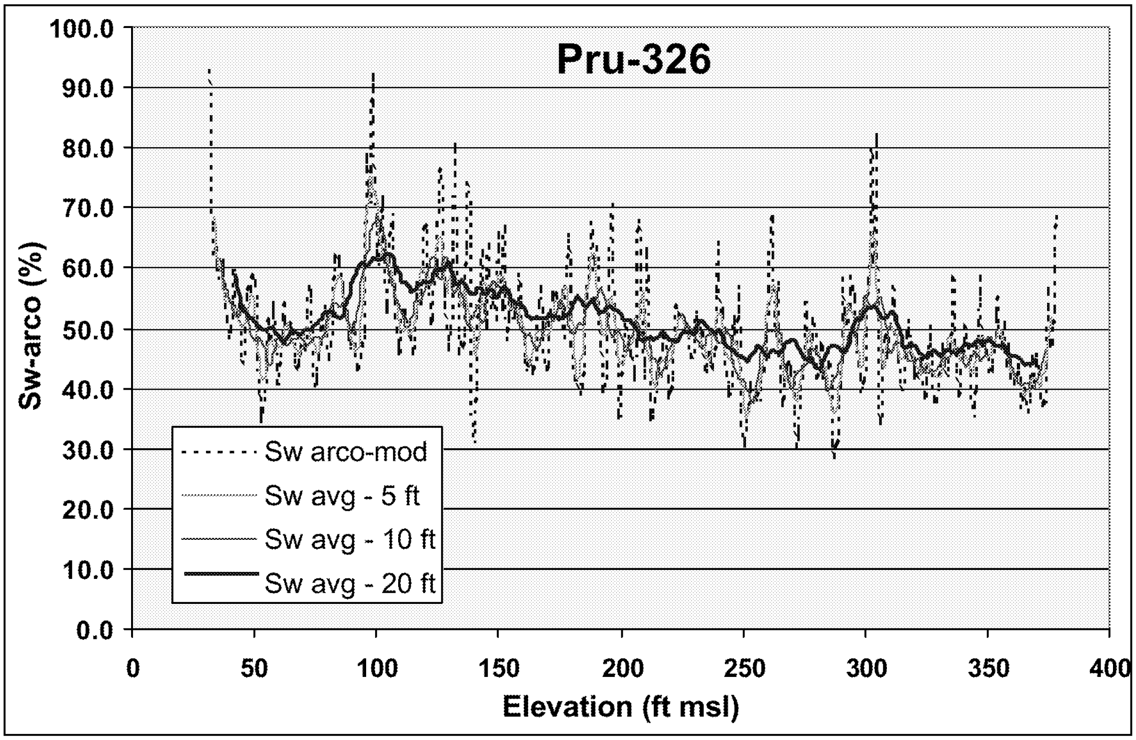


Figure 3-32: Sw values in the Monarch Sand reservoir calculated from the Pru-326 well log plotted by elevation msl. The fitted curves are the 5 ft, 10 ft and 20ft moving average for So values plotted in the dotted curve.

To better capture the coarser-scale variation in Sw, profiles were constructed representing 5 ft moving averages of the half-foot spaced Sw values calculated from log data. By nesting the profiles for clusters of wells, it is relatively easy to see the magnitude of spatial variation in Sw, or more significantly So, oil saturation. The four two-acre patterns that form the Pru Fee pilot are located in the portion of the property where oil saturations in the upper half of the pay interval are largest (Fig. 3-34) and where the "ideal" Sw profile demonstrated in the Pru-101 core and log data is best represented. In contrast, the group of four patterns along the western edge of the property (Fig. 3-35), adjacent to the produced Kendon lease, show substantially lower oil saturations in the upper half of the pay interval and less vertical variation in saturations in general.

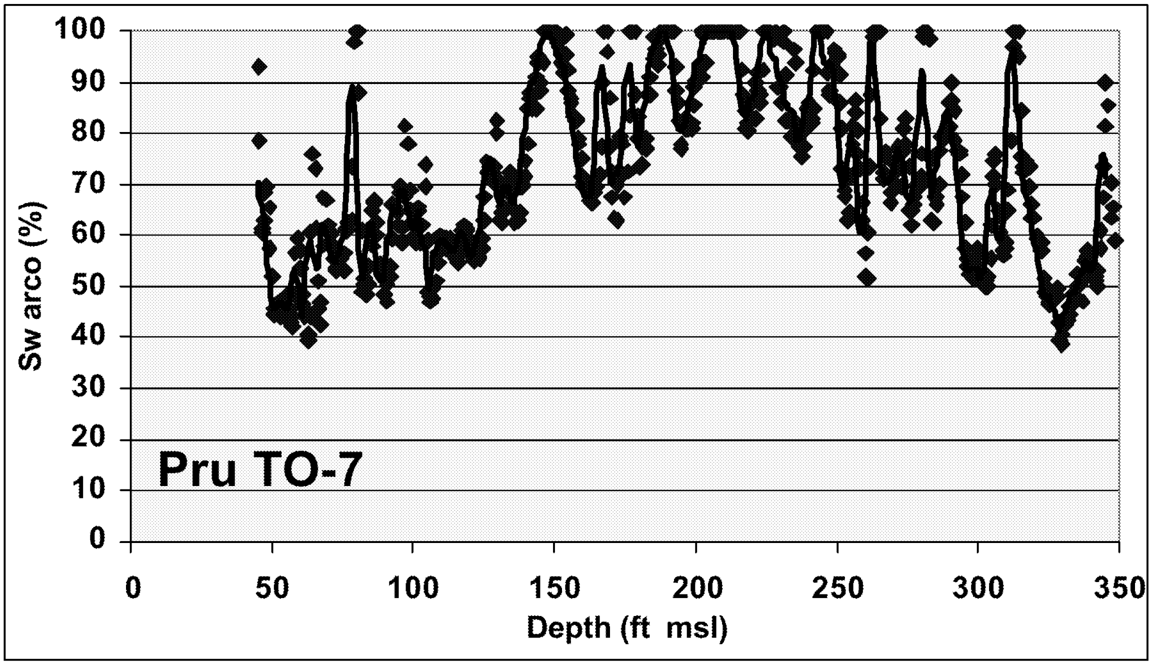


Figure 3-33: Sw values in the Monarch Sand reservoir calculated from the Pru TO-5 well log plotted by elevation msl. The fitted heavy curve is the 5 ft moving average.

It is the four patterns along the northern edge of the Pru property (Fig. 3-36) that are the most different from the others. Several of the Sw profiles for wells in these patterns exhibit nearly complete depletion of oil within the upper half of the Monarch Sand reservoir. These patterns are adjacent to the Aera Energy LLC Nevada lease, which has been in intensive cyclic production for many years. The effects of this production are being noticed within the adjacent portions of Pru Fee, as is evidenced by the very high reservoir temperatures recorded even prior to the onset of steam flood.

The spatial variations in the Sw profiles appear to relate solely to prior oil production activity in the different parts of the Pru Fee property. Before the present DOE-sponsored steam flood project demonstration project began in 1995 there is record of more than 1.8 million bbls of oil having been produced from the property, most of that in primary.

In order to develop a more detailed model of the spatial variations in oil saturation that could be used to better manage the Monarch Sand reservoir a series of contour maps (Figs. 3-37 to 3-39) have been generated. These maps show the 20-ft moving average value of So (oil saturation!) at elevations separated by 20 feet. Thus, the values contoured in the 200 ft map, for instance, are the 20-ft moving average values in all wells at an elevation of 300 ft. The map is capturing the average So values within a 20 ft slab of the Monarch Sand reservoir 10 ft above to 10 ft below the elevation datum. Although this method is smearing out the small-scale variability in So, it is capturing the large-scale variability significant to improved reservoir management.

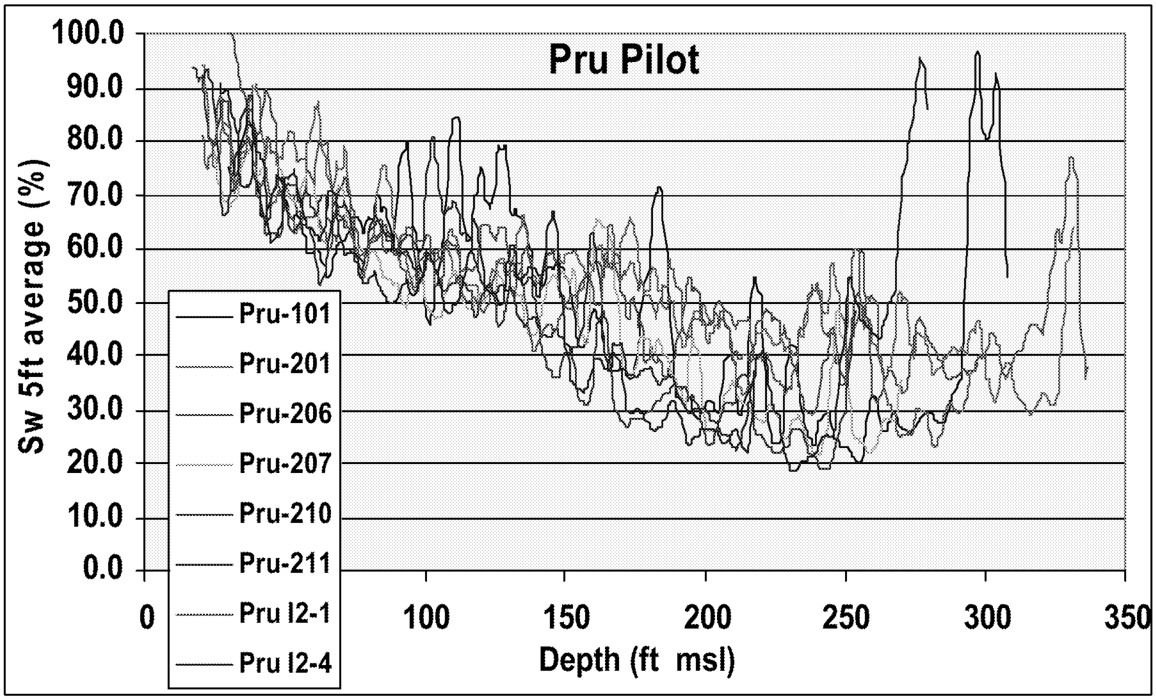


Figure 3-34: Nested 5-ft moving average Sw curves for a selection of wells within the 8 acre Pru Fee steam flood pilot at the center of the 40 acre property.

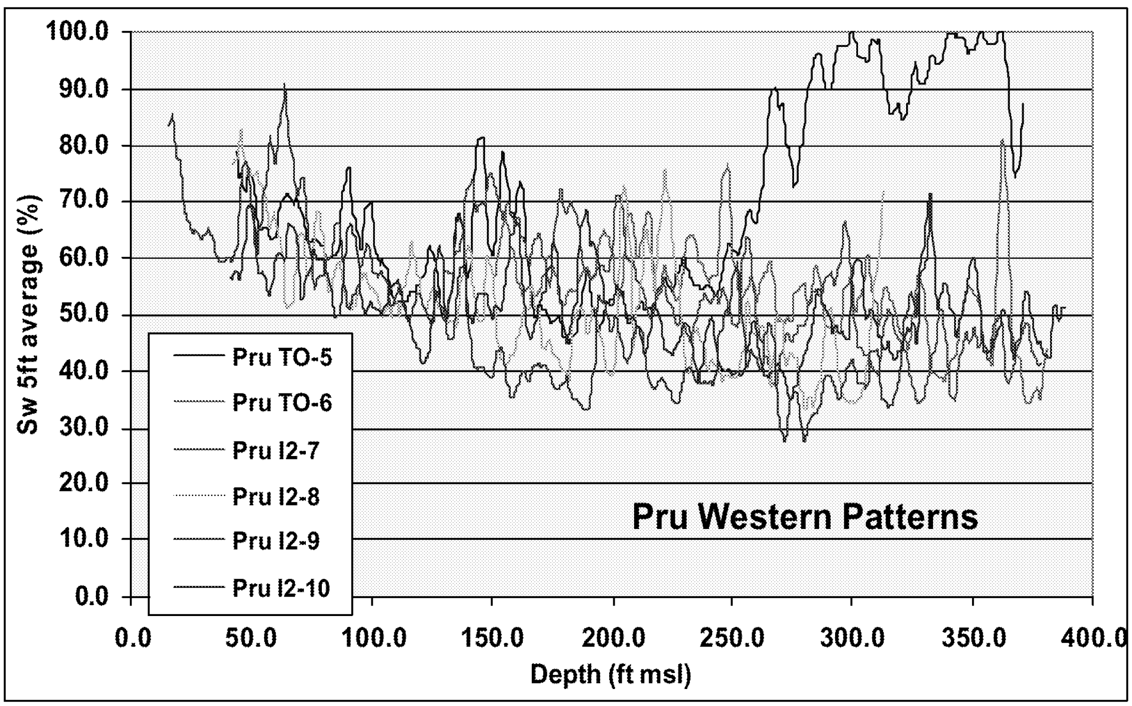


Figure 3-35: Nested 5-ft moving average Sw curves for a selection of wells within the four steam flood patterns along the western margin of the Pru Fee property and bordering the producing Kendon lease.

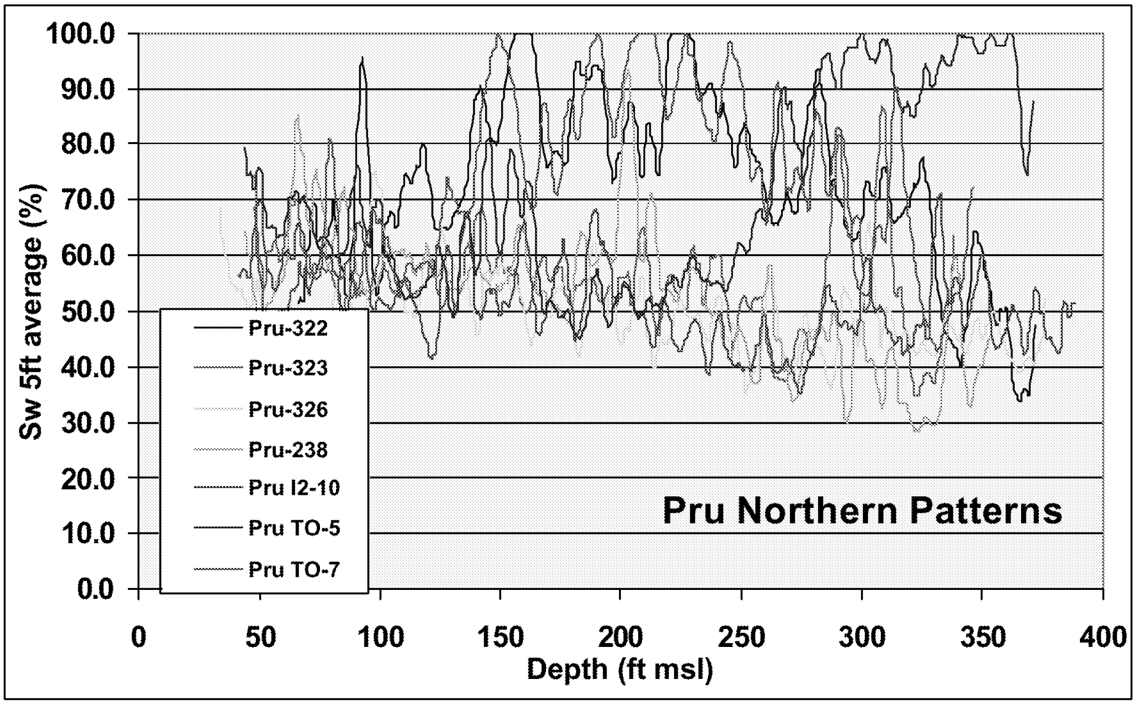


Figure 3-36: Nested 5-ft moving average Sw curves for a selection of wells within the four steam flood patterns along the northern margin of the Pru Fee property and bordering the producing Nevada lease.

As described above, the upper bounding surface of the Monarch Sand is dipping at about 10° to the southeast. In the northwest half of the property this surface is the unconformity at the base of the Etchegoin Formation, but to the southeast it is the base of a diatomite interval that encloses the Monarch Sand. The dip of the Monarch Sand body is about 3° greater than that of the base of the Etchegoin Formation. Horizontal slices through the Monarch Sand body at 20 ft intervals first intersect the sand in the northwest corner of the property where the top of the sand is as high as 400 ft msl. In the current analysis, the highest elevation contoured is 300 ft msl, which captures useful So values in just about one-third of the property. A 240 ft elevation slice just barely captures So values across most of the property in which there is well control.

The set of 12 contour maps of So at 20ft depth slices between 300 ft msl and 80 ft msl are presented in Figures 3-xx to 3-xx. In viewing these maps it is advised to refer to the contour maps depicting the upper bounding surface of the Monarch Sand (Fig. 3-xx), the "top Monarch" surface, and the OWC (Fig.3-xx). These maps deserve careful study as they contain a wealth of information about the spatial distribution oil remaining within the reservoir. However, the maps do not depict a "snapshot" of the oil distribution at any single time. The well logs from which the maps are ultimately derived were run over the period from late 1995 through late 1999. During this four-year period oil continued to be produced from the Pru Fee and adjacent properties. Yet they remain a valuable guide for ongoing management of the Monarch Sand reservoir.

The most prominent feature observed in the higher elevation contour maps is a distinct NE-SW trending "ridge" of So in the range 60-75% situated to the northwest of the Monarch Sand truncation line. This ridge is the horizontal expression of the So profile observed in Pru-101 (Fig. 3-37) and characteristic of most wells in the central part of the property. The lower So values along the truncation line are the "oil depleted zone" at the top of the Monarch Sand. The "ridge" is the interval of high So values 25 to 150 ft below the top of the sand, and the falling off of So to the northwest is an expression of the gradual downward reduction in So towards values <30% immediately above the OWC. As expected, the position of the "ridge" shifts progressively southeastward in successively lower elevation slices. The variation in the shape of the "ridge" from one elevation slice to another reflects the lateral heterogeneity oil saturation within the reservoir.

Two regions of especially low So stand out in the contour maps (Figs. 3-37 to 3-39). Near the northwest corner of the property is a circular "hole" with extremely low So values at elevations above 260 ft msl. This hole dies out downward into regions of the reservoir with higher (>45%) So and has no expression below 220 ft msl. Although relatively small, it is not a single well feature. Along the north-central edge of the property a broad depression in So values develops below 300 ft msl. This feature intensifies with depth down to 140 ft msl and only begins to fade into slightly higher So at about 100 ft msl. Nevertheless, a weak depression of So continues to exist even at 80 ft msl. As will be discussed later in the report, these major depressions appear to be related to areas of intense prior production from the Monarch Sand reservoir.

Average So values determined from the group of values contoured in each elevation slice aid in depicting the gross distribution of oil within the reservoir. As expected, they are considerably higher in the upper portions of the reservoir, >50%, and gradually drop off less than 50% below 140 ft msl and less than 40% below 100 ft msl. At the 60 ft elevation (Fig. 3-40) the average So is just 35.5%. At this level there is a curious inversion of oil saturation such the higher values exist beneath the broad depression in So along the north-central part of the property and the lowest values are found beneath the pilot and patterns immediately to the west, the region of generally high So higher in the reservoir. At 40 ft msl, just immediately above the OWC, the average So is 27.4%.

In contouring the average So values determined through the entire pay zone of each well (Fig. 3-40) little variation is observed except for the two So "holes" in the northwest and north-central parts of the property. The average So for the reservoir as a whole is 46.7 %. Considering the large-scale variability of So observed in the separate elevation slices, this is clearly the wrong way to examine the distribution of oil within the reservoir. There is a large volume of the Monarch Sand in which So exceeds 60%. This is the appropriate targets for current and future production.

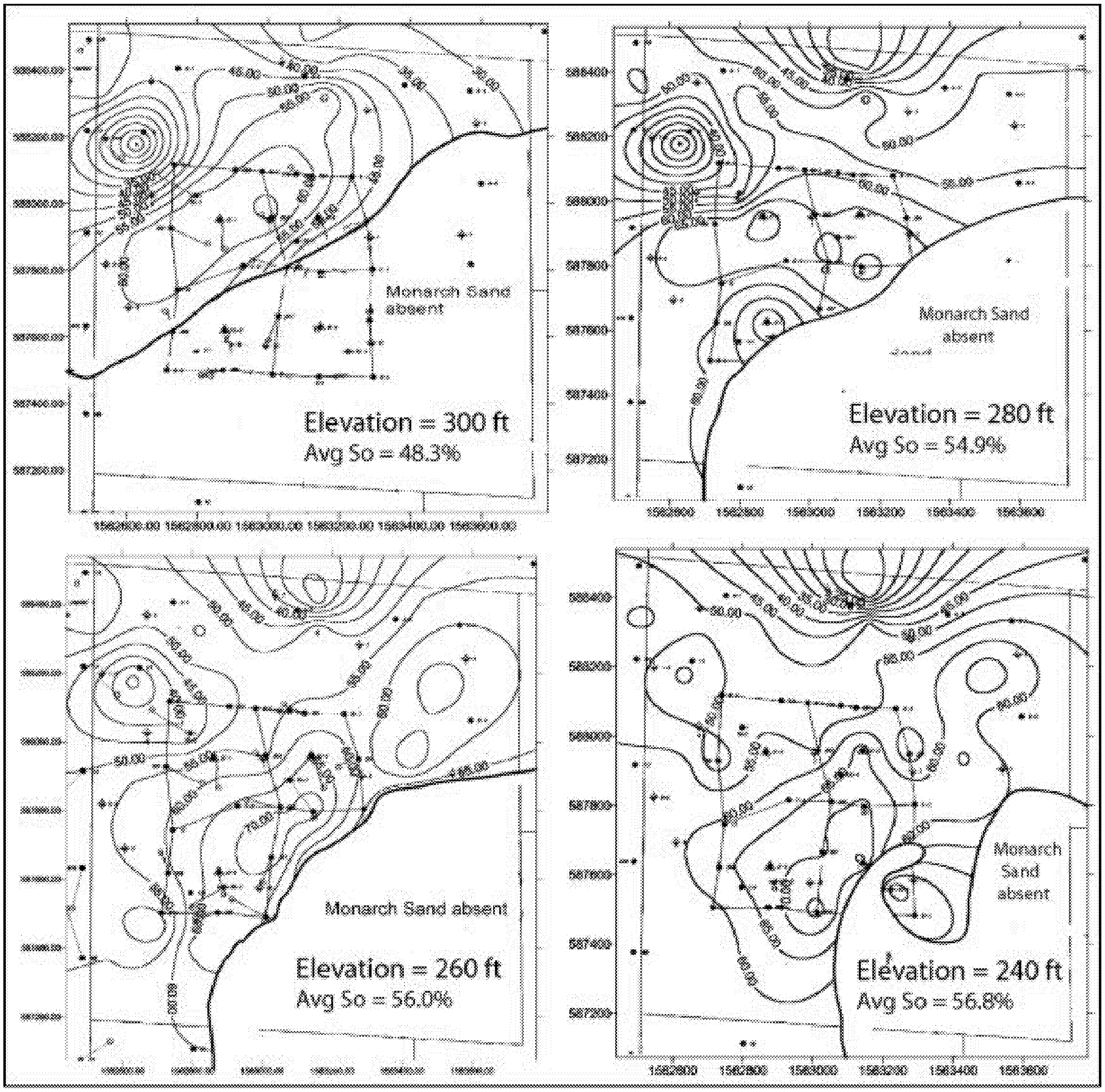


Figure 3-37: Maps showing the distribution of oil within the Monarch Sand reservoir at different elevation slices. The values contoured are the 20-ft moving average of So-arco at the elevation of the map. The maps depict the lateral variability in oil saturation within a 20 ft thick interval of the reservoir 10 ft above to 10 ft below the map datum.

<u>300 ft msl</u>: Note the "ridge" of So in excess of 60% just northwest of the truncation line of the Monarch Sand and parallel to the truncation. Also note the pronounced "hole" in So in the NW corner of the property where the reservoir is depleted of oil.

<u>280 ft msl</u>: Note the development of a second depression in So along the north-central part of the property.

<u>260 & 240 ft msl</u>: Note the continued presence of the high So "ridge" and the broadening of the northern depression. The NW circular "hole" is dying out downward.

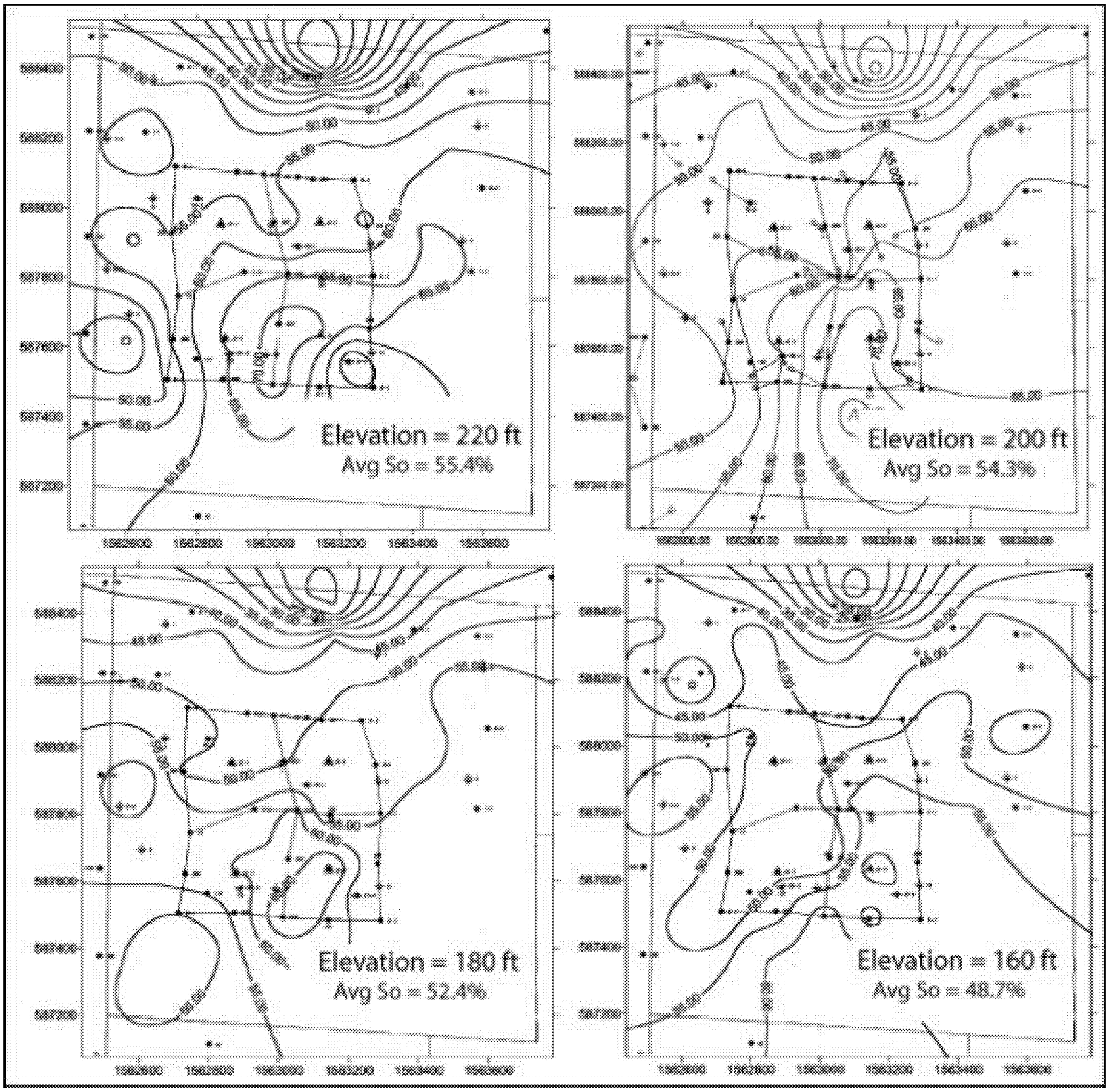


Figure 3-38: Maps showing the distribution of oil within the Monarch Sand reservoir at 220 ft to 160 ft elevations. The values contoured are the 20-ft moving average of So-arco at the elevation of the map. The maps depict the lateral variability in oil saturation within a 20 ft thick interval of the reservoir 10 ft above to 10 ft below the map datum.

<u>220 ft msl</u>: At this depth the reservoir is completely beneath the upper bounding surface and the "ridge" of high So has shifted even further to the SE.

<u>200 & 180 ft msl</u>: The distinct "ridge" of elevated So is contracting as a consequence of the larger distance beneath the top of the reservoir and higher internal heterogeneity is evident.

<u>160 ft msl</u>: The broad low So depression remains strong at this level, which otherwise is clearly different from the elevation slices immediately above and below.

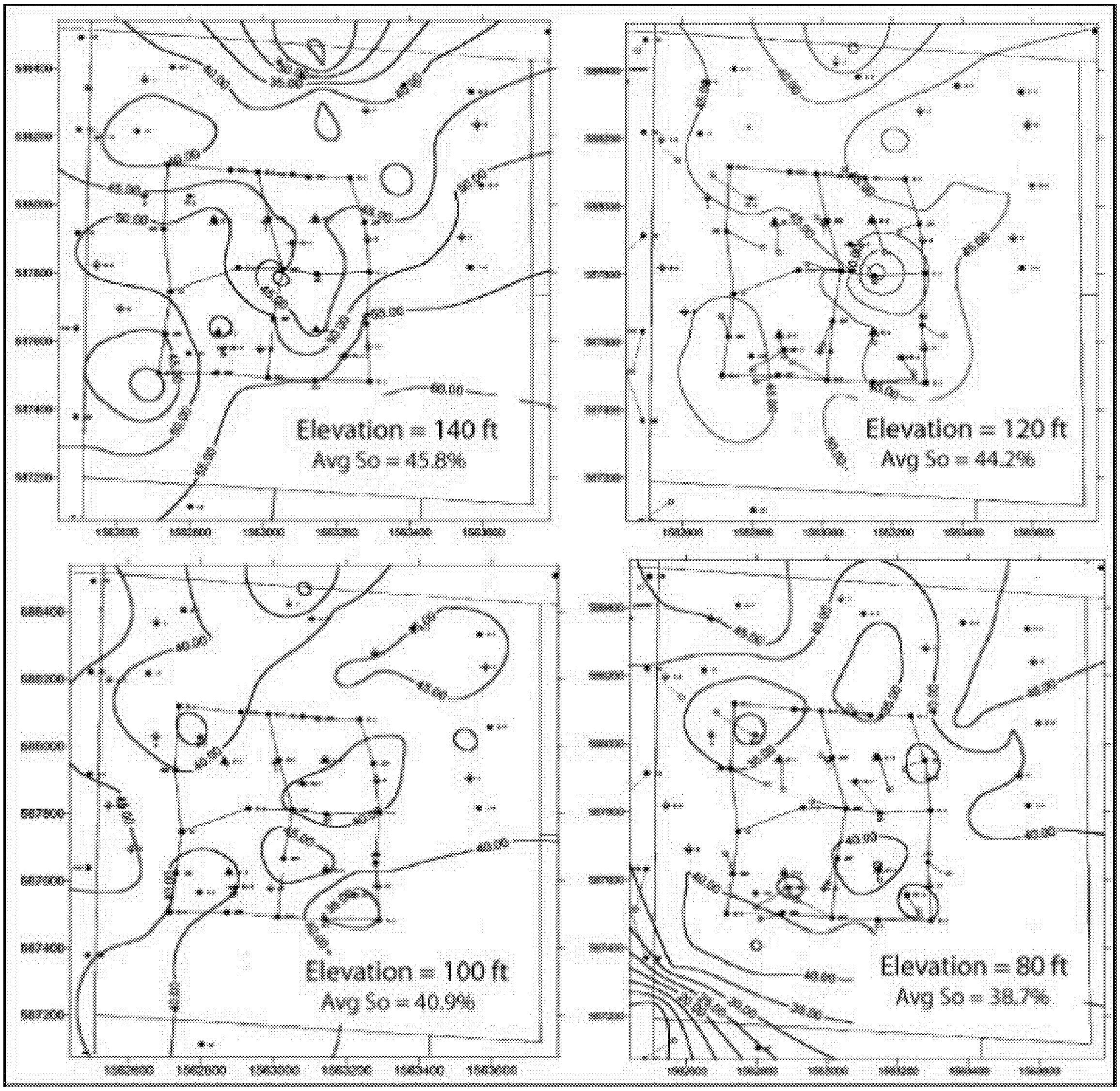


Figure 3-39: Maps showing the distribution of oil within the Monarch Sand reservoir at 140 ft to 80 ft elevations. The values contoured are the 20-ft moving average of So-arco at the elevation of the map. The maps depict the lateral variability in oil saturation within a 20 ft thick interval of the reservoir 10 ft above to 10 ft below the map datum.

<u>140 ft msl</u>: As the overall values of So fall the distinct So features of higher levels are beciming more subdued.

<u>120 ft msl</u>: The circular "hole" in the NW is completely gone and the broad northern depression is disappearing.

<u>100 & 80 ft msl</u>: At relatively low values of So (>40%), the maps are showing very little lateral variability within the deeper parts of the pay zone. The apparent depression in the SW corner of the property at 80 ft msl is clearly an artifact of contouring.

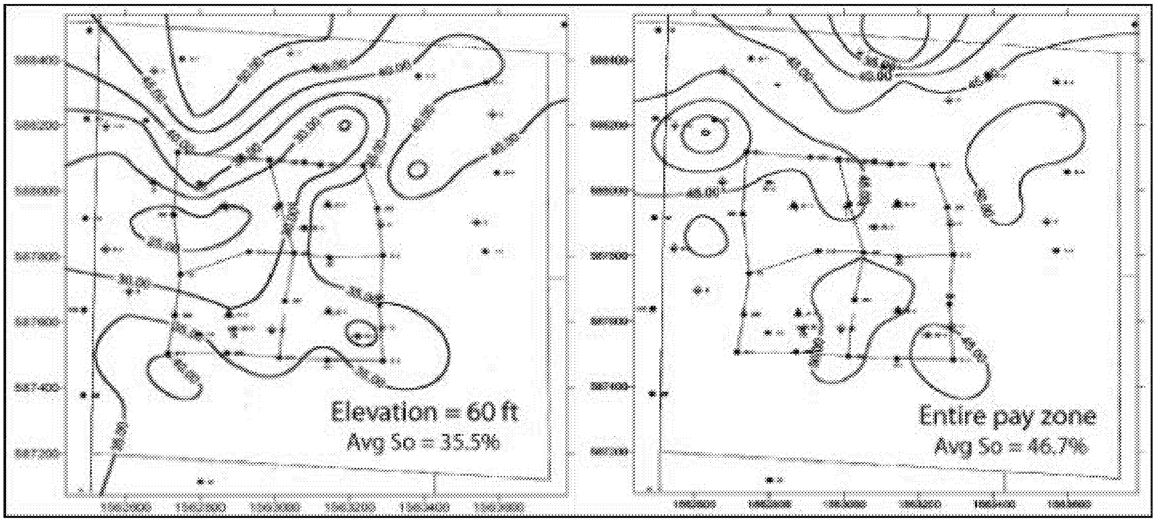


Figure 3-40: Maps showing the distribution of oil within the Monarch Sand reservoir at 60 ft elevation and for the entire Monarch Sand pay zone. The values contoured are the 20-ft moving average of So-arco at the elevation of the map.

<u>60 ft msl</u>: This level exhibits a curious inversion in which the highest So is beneath the north-central depression of So and the So trough is beneath the higher So "ridge". The average So for the entire level is a very low 35.5%.

<u>Entire pay zone</u>: Taken as a whole the Monarch Sand reservoir shows little statistical variation in So, except for the depressions in the NW and north-central parts of the property.

Chapter 4

Buildup of Heat During the Thermal Recovery Process

Introduction

The progressive buildup of heat within the Monarch Sand reservoir is monitored by two means: 1) a series of temperature observation wells interspersed within the array of injectors and producers and 2) the temperature of produced fluids. A single temperature observation (TO) well positioned near the new Pru-101 producer was drilled in September 1995 and monitored through January 1996. Three additional temperature observation wells were installed in early 1997 at the time of startup of the four-pattern steam flood pilot. The four TO wells in the pilot have been logged just ten times during the period June 1997 through February 2001. At the time of conversion of the "300-series" cyclic producers to steam flood patterns three additional temperature observation wells were installed, one each in the southwest, northwest and north-central portions of the 40 acre Pru Fee property. These wells have been logged three times, in December 1999-January 2000, before the steam flood patterns became fully operational, in July 2000 and again in February 2001.

Initial Temperature of Monarch Sand Reservoir

When steam injection first began in November 1995 at the beginning of the cyclic baseline testing the Monarch Sand reservoir on the Pre Fee property had not received steam for a period of nearly 14 years. The initial thermal recovery efforts by Tenneco Oil and Gas in the northern three-fourths of the property had lasted less than two decades and the period of serious steam cycling of producers extended over fewer than 12 years, ending in February 1982. Pru-533 had been cycled twice in 1985 on a trial basis, but that involved only a single well. Nevertheless, a considerable volume of steam (1,692,466 bbls) had been injected into the reservoir and it was natural to expect to encounter some residual heat during the earliest temperature logging.

The temperature observation well TO-1 located near the very center of the property (Fig. 4-1) was drilled and first logged in the autumn of 1995, During the period of the onset of steam cycling in renovated wells and the nearby Pru-101 well, it was logged four times on one-month intervals starting October 26 to check on the effectiveness of steam injection. The resulting logs collected in October and November indeed do show a residual heat perturbation in the upper part of the Monarch Sand of just about 10° F (Fig. 2-2). By late December and January temperature was already rising within a very narrow interval near the top of the Monarch Sand, and also within sands the Tulare Formation. It was suspected that steam was escaping along the outside of the Pru-101 casing and finding its way into the higher sandy interval at about 500 ft depth. Repairs were made to the well to prevent further up-hole loss of steam. These first temperature logs suggest that the "natural" temperature of the Monarch Sand on the property is in the range 90-

100º F. This is confirmed by the temperatures observed in TO-6 drilled in the previously un-produced southwest corner of the property (Fig. 4-1)

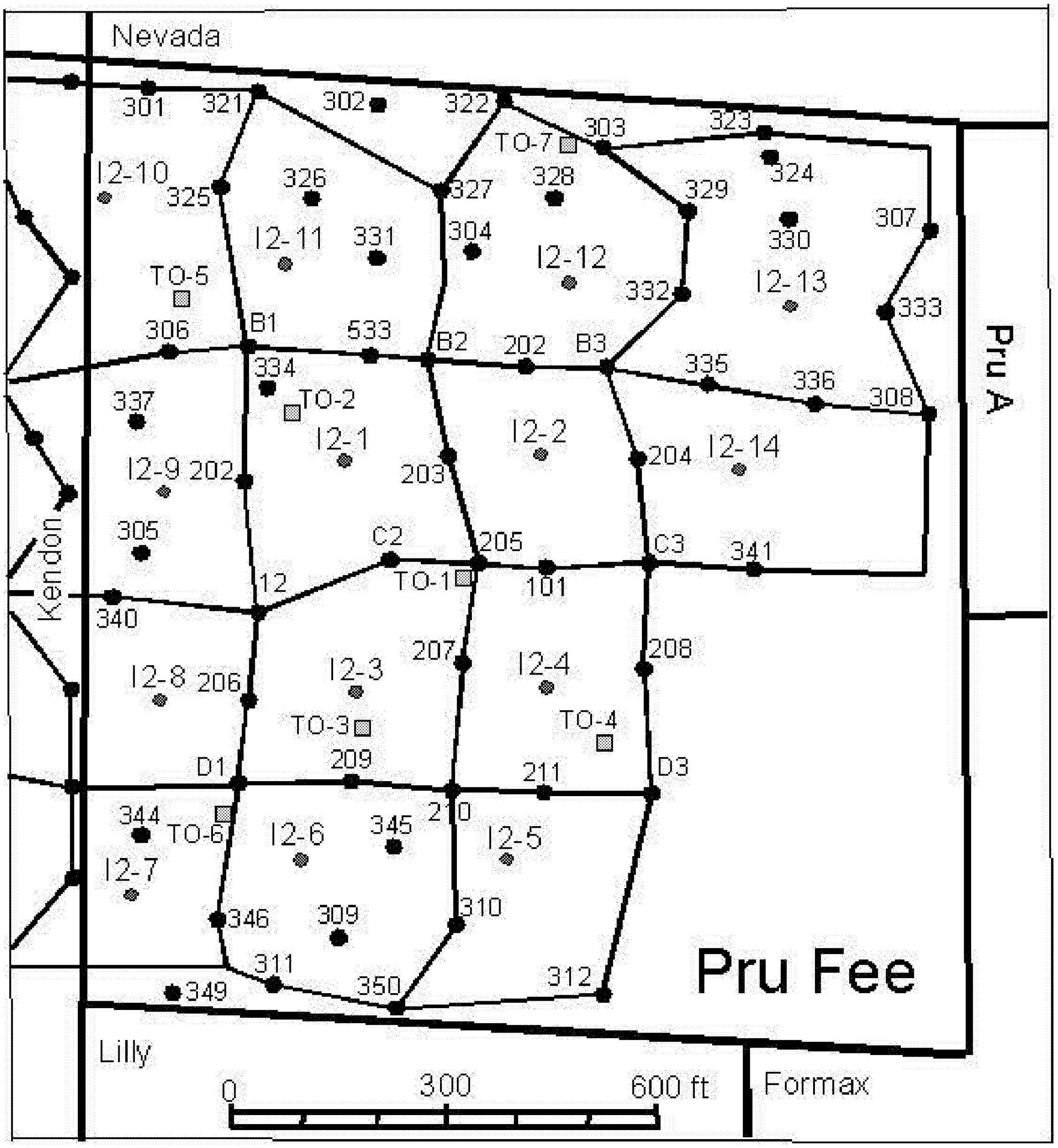
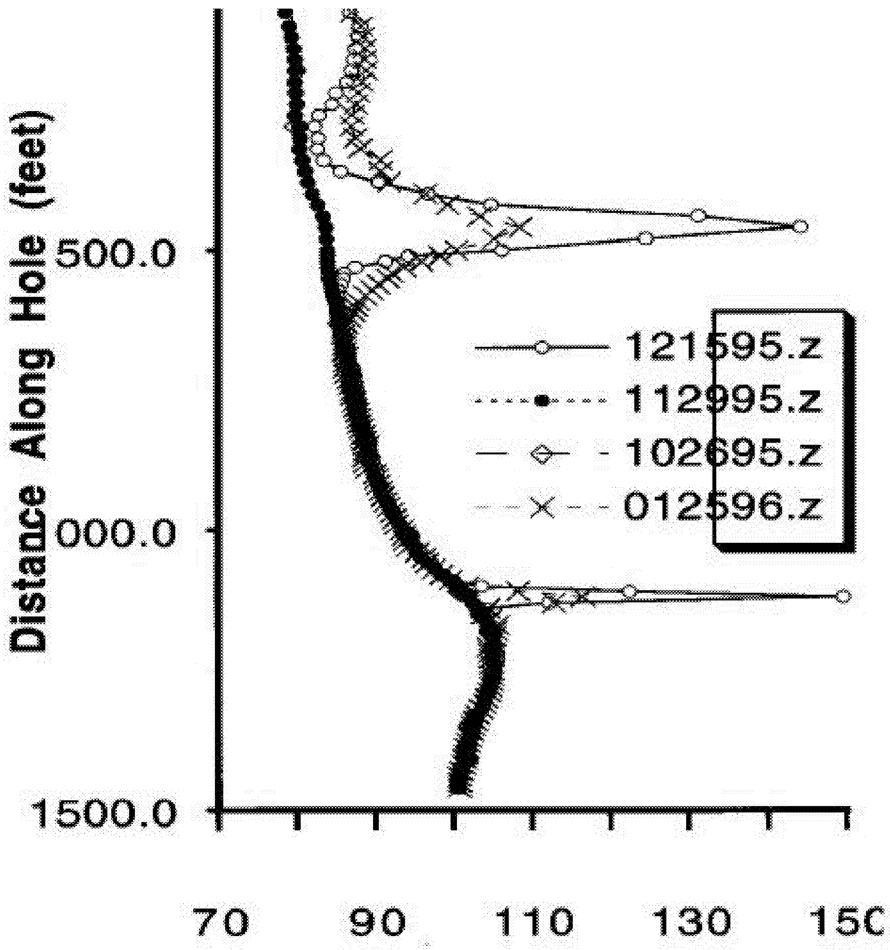


Figure 2-1: Location of the temperature observation wells on the Pru Fee property.



.Figure 4-2: Temperature logs from the TO-1 well near the center of the Pru Fee property. The logs, taken October 26, 1995 and in one-month intervals thereafter, record the invasion of steam from the nearby Pru-101 into the Monarch Sand (top at 1090 ft depth) and the higher Tulare sands. The October and November logs indicate the presence of a small quantity of residual heat in the Monarch Sand from the earlier thermal recovery operations. The highest temperature recorded in these first two logs is 105°F, just about 10° F above the 90-100° F "natural" temperature of the reservoir.

After January 25, 1996, when the last of the initial temperature logs in TO-1 (Fig. 4-2) was taken, temperatures in the Monarch Sand reservoir were not monitored again until the end of June 1997, a gap of 17 months. During the intervening time the baseline test wells had continued to be cycled. The steam flood pilot had been installed, including three additional temperature observation wells, and was already operating for about six months. Thus, 328.2 Mbbls of steam had been injected into the central part of the Pru Fee property. Even so, only one of the temperature observation wells, TO-3 in pattern 3 (Fig. 4-2), showed any appreciable rise in temperature with peaks at 224.8° and 262.4° F. The TO-3 well is very close to the Pru 12-3 injector. The maximum temperatures in the other wells were 128.2º (TO-1), 123.0º (TO-2), and 117.2º (TO-4). The peak June 1997 temperatures were all within the upper parts of the Monarch Sand.

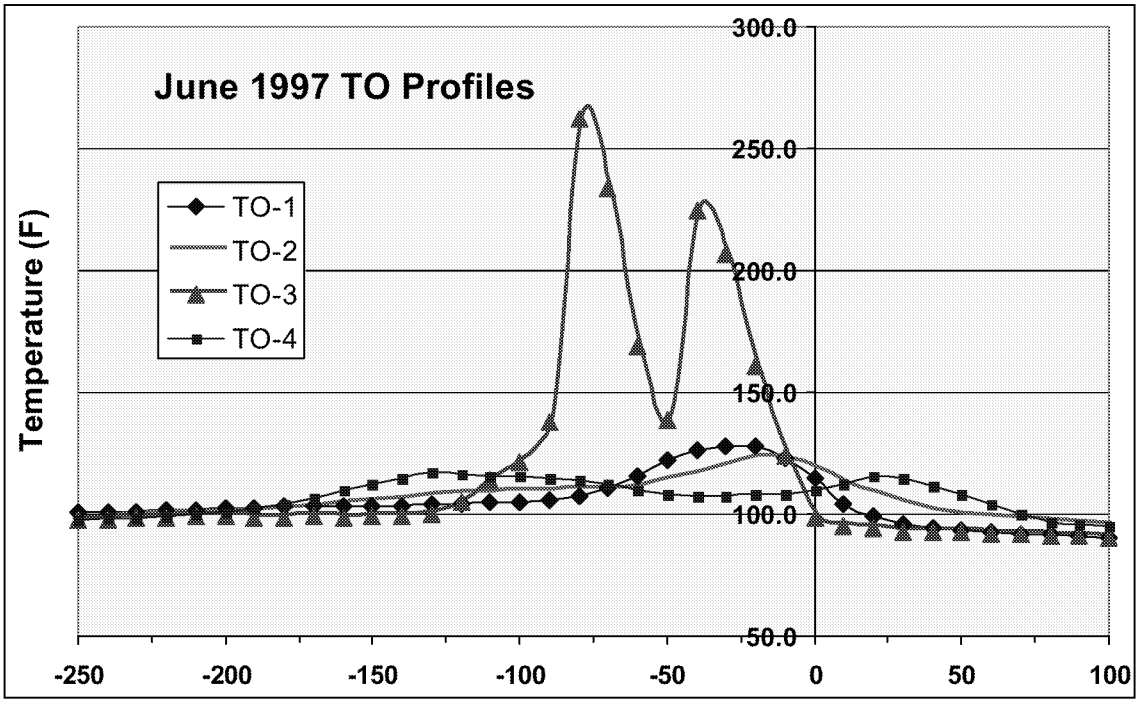


Figure 4-3: Temperature logs gathered on June 26, 1997. These were the first logs taken since the beginning of the steam flood pilot and after 328.2 Mbbls of steam had been newly injected into the Monarch Sand reservoir. Depths are relative to the top of the Monarch Sand to show the gradual buildup of heat in the reservoir. However, TO-3, located very close to an injector, exhibited very rapid heating along specific stratigraphic intervals.

Heat Buildup in Steam Flood Pilot

During the first two years of operation of the steam flood pilot, the four temperature observation wells were logged on a regular basis to track the buildup of heat within the Monarch Sand reservoir. However, in the period of transfer of ownership between ARCO Western Energy and Aera Energy LLC, this activity was suspended. Thus, a nine-month gap in temperature logging exists between September 10, 1998 and June 15, 1999. The wells were logged again in late 1999-early 2000. Temperatures in the Monarch Sand reservoir after the entire property was converted to steam flood in early 2000 are described in a separate section.

The progressive buildup of heat in the four temperature observation wells since the onset of the steam flood operation in the spring of 1997 is displayed in Figures 4-5 through 4-8. The depths in the wells are expressed as elevations relative to sealevel. Each injector well is a solid pipe perforated at six points about 10 ft apart. The lowest perforation has a standoff from the OWC in excess of 100 ft. It is important to note that during the entire period of temperature record, the points of steam injection were unchanged. Also, it should be noted that the original reservoir temperature prior to steam injection was close to 100° F. This "natural" reservoir temperature is preserved in the deeper parts of the Monarch Sand.

Table 4-1 provides information about a) the distances of each temperature observation well from the nearest injector, b) the elevations of the top of the Monarch Sand reservoir and the OWC, and c) the distance/elevation of the top and bottom of the injection interval in the nearest injector relative to the top of the reservoir and OWC. It is obvious that the initial thermal response to steam injection recorded in each temperature observation well is roughly proportional to its proximity to an injector well. However, the specific pattern of reservoir heating implicit in the temperature logs varies with location.

The strategy for optimizing steam flood production in the pilot is to put the heat into the upper part of the Monarch Sand reservoir where the oil saturations are observed to be highest (greater than 50%), and avoid heating the lower half of the pay interval where water saturations generally exceed 60-70%. The heat capacity of water is more than twice that of crude oil (Burger et al., 1985) so that heat is lost disproportionately to formation water. The commercial objective of the project is to produce heavy oil, not hot water. The temperature observation logs provide critical data for knowing if the reservoir heating objectives are being reached.

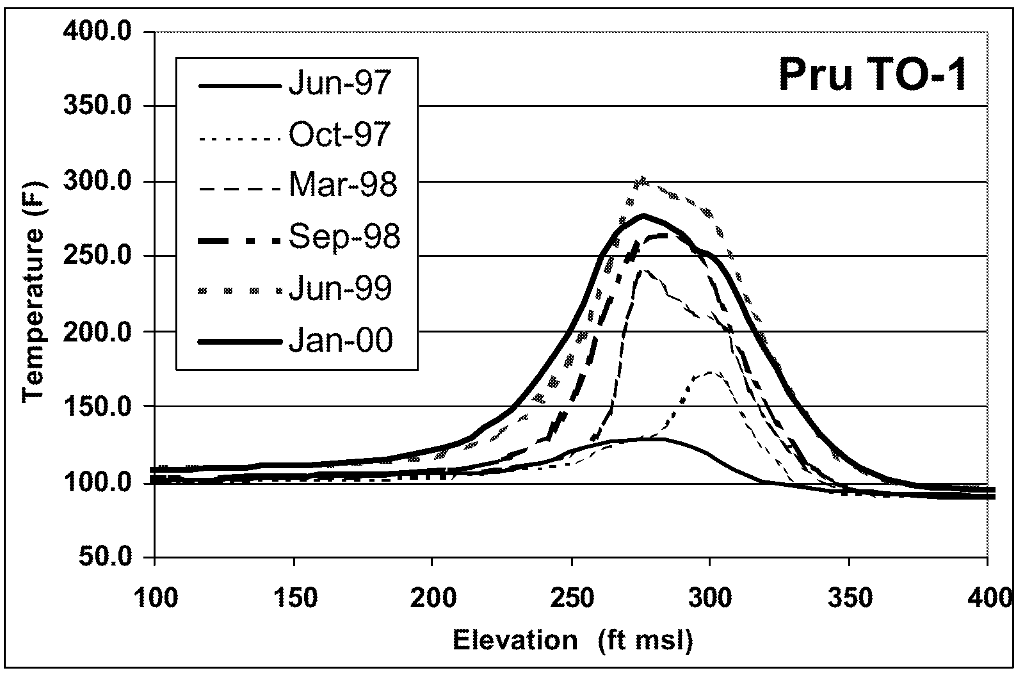


Figure 4-5: Stacked temperature logs for the Pru TO-1 well, which is 100 ft from the nearest injector well. Top of Monarch Sand = 300 ft; OWC = 30.5 ft.

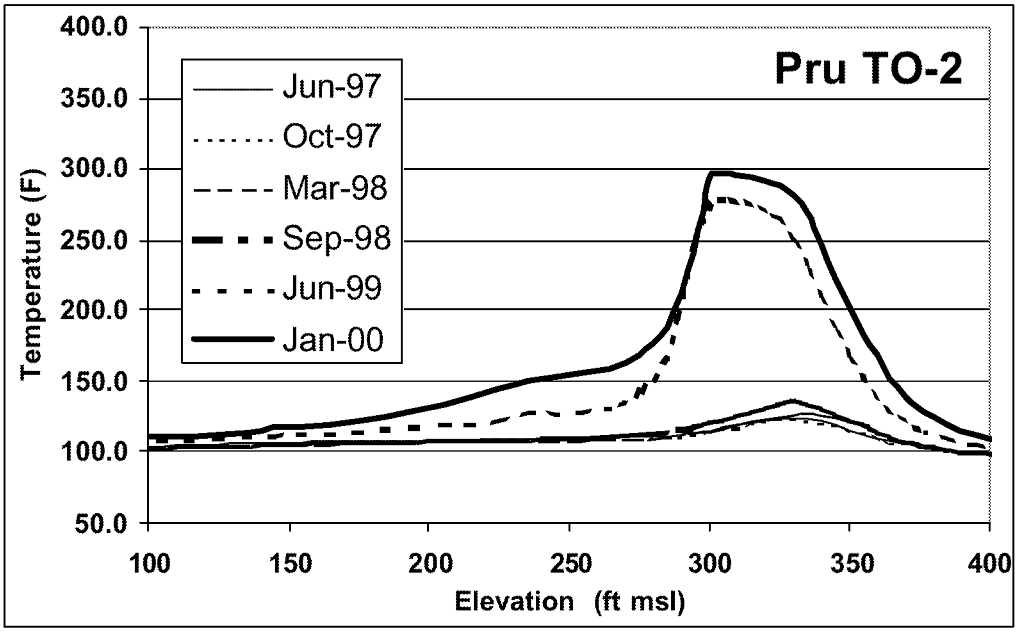


Figure 4-6: Stacked temperature logs for the Pru TO-2 well, which is 90 ft from the nearest injector well. Top of Monarch Sand = 350 ft; OWC = 31.8 ft.

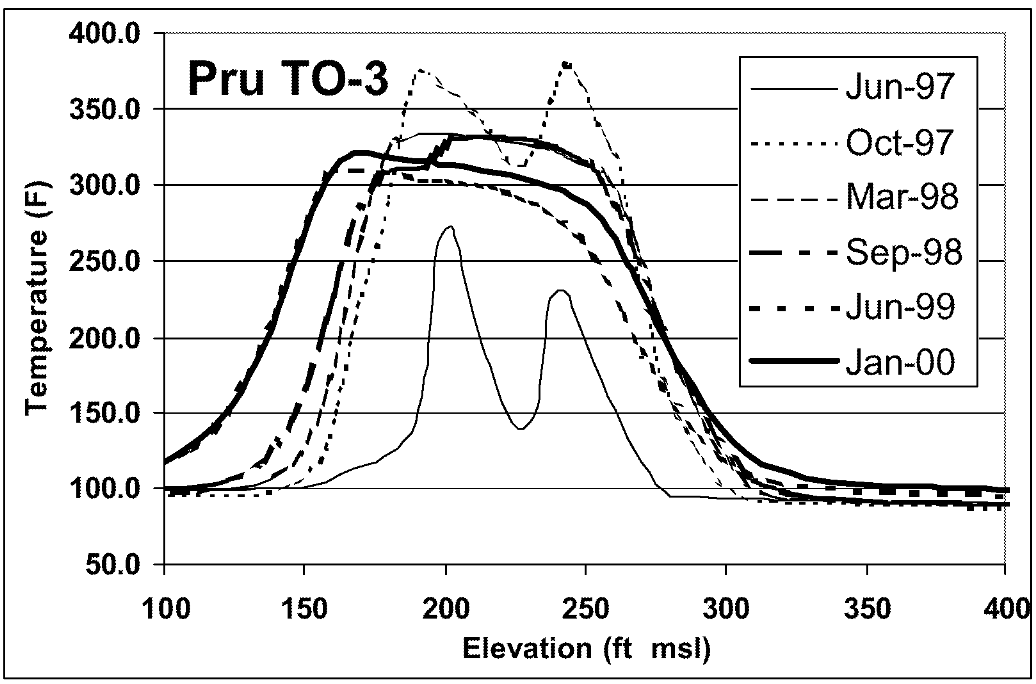


Figure 4-7: Stacked temperature logs for the Pru TO-3 well, which is 45 ft from the nearest injector well. Top of Monarch Sand = 278.5 ft; OWC = 32.8 ft.

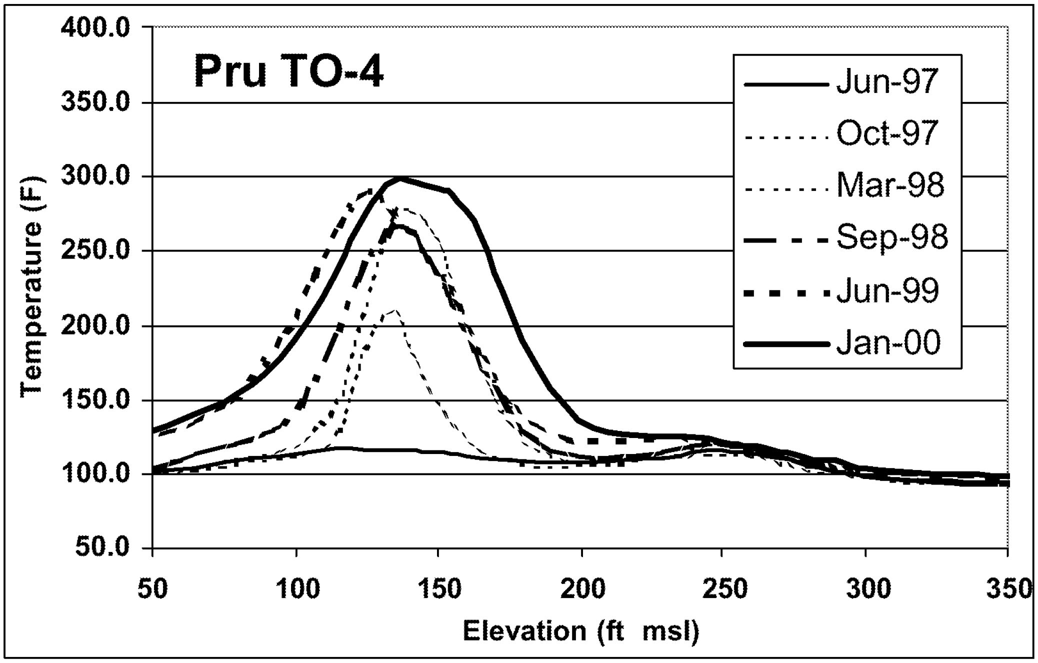


Figure 4-8: Stacked temperature logs for the Pru TO-4 well, which is 110 ft from the nearest injector well. Top of Monarch Sand = 222.6 ft; OWC = 25.9 ft.

The dip of strata within the Monarch Sand at the four-pattern pilot is 10° to the southeast. At this dip, the strata would be expected to drop about 18 ft for every 100 ft of horizontal distance to the southeast. Two of the temperature observation wells (TO-3, TO-4) are situated to the southeast, downdip, of their nearest injector (Fig. 4-1). The TO-2 well is updip and the TO-1 well is on strike to the southwest (Table 4-1). If indeed the steam remained confined within the strata in which it was injected, we could expect that the "hot" interval in the temperature observation wells, designated for convenience as that over 200° F (Table 4-1), would be of similar thickness and elevation as the perforation interval within the nearest injectors. Yet this is not entirely what is observed. In two instances (TO-1, TO-2), the steam rises about 50 ft, somewhat more than can be explained by the inclination of the strata. In another case (TO-3), it spreads upward and downward about 40 ft in each direction. Only in one instance (TO-4) does the steam appear to be constrained by stratigraphic barriers. In the first three wells, it is clear that the top of the steam chest is constrained principally by the overlying less permeable silts and shales of the Etchegoin Formation.

Table 4-1: Information related to Temperature Observation Wells

	TO-1 well	TO-2 well	TO-3 well	TO-4 well
Nearest injector	I2-2	I2-1	I2-3	I2-4
Distance/direction to injector	100 ft/NE	90 ft/SE	45 ft/NNW	110 ft/NW
Elevation top reservoir	300 ft	350 ft	278.5 ft	222.6 ft
Elevation of OWC	30.5 ft	31.8 ft	32.8 ft	25.9 ft
Thickness of zone >200° F	68 ft	67 ft	139 ft	74 ft
Elevation interval > 200° F	318/250 ft	350/283 ft	278/139 ft	178/104 ft
Nearest injector				
Elevation top/base perf.	262/206 ft	290/243 ft	233/173 ft	209/153 ft
Offset - top perforation	47 ft	39 ft	47 ft	44 ft
Offset – base perforation	103 ft	86 ft	107 ft	100 ft
Offset base from OWC	202 ft	187 ft	161 ft	131 ft

Note: The viscosity of the Pru Fee crude oil at 200° F is measured as 37 cp.

The major features in each set of temperature observation well logs are described below:

TO-1 well: The temperature logs (Fig. 4-5) record a very regular heating of the Monarch Sand reservoir through time and a relatively tight zone of heating within the upper 50 ft interval of the reservoir. The maximum temperature recorded is 296.7° F reached in June 1999 after 27 months of steam injection in the I2-2 well 100 ft to the northeast. In the subsequent six months to January 2000 the well has cooled slightly to a maximum temperature of 275.2° F. The interval of temperatures greater than 200° F extends about 18 ft into the overlying Etchegoin Formation, probably due to thermal conduction.

TO-2 well: Curiously this well (Fig. 4-6) in the northwest quadrant, only 90 ft from the nearest injector, showed very sluggish build up of heat in the Monarch Sand reservoir. In the nearly two years of steam injection through September 1998 the maximum temperature had risen only about 30° and was virtually static. However, in the next 9 months of record, the maximum temperature jumped about 150° F to stand at 280° F. In the subsequent 6-month interval to January 2000 the maximum temperature rose to 296.8° F and the "hot" interval broadened slightly to span the upper 67 ft of the Monarch Sand. It is probable that the late thermal pulse is not from the injector, but rather from the Pru-334 well just 60 ft to the northeast (Fig. 2-3) that was primed with 8,976 bbls of steam in November-December 1998 and 14,723 bbls of steam in May-June 1999. The relatively flat bottom recorded in the recent temperature curves (Fig. 4-2) coincides with a 7 ft diatomite-rich interval within the otherwise rather massive Monarch Sand.

TO-3 well: This well in the southwest quadrant (Fig. 4-7), which is only 45 ft away from its nearest injector, has shown a bizarre history of reservoir heating. Whereas all of the other temperature records indicate slow progressive heating of the reservoir with time, the steam reaching this well rapidly "fingered" along specific strata. Maximum temperature of about 380° F was recorded in October 1997, only 7 months after steam injection began. Since then the temperature profile has broadened and has cooled back to a maximum 321° F (January 2000). The interval of elevated (>200°) temperature is 139 ft thick, twice that in the other temperature observation wells.

TO-4 well: This well in the southeast quadrant is the most distant, 110 ft, from its nearest injector. The temperature logs (Fig. 4-8) record the gradual heating of the reservoir, which stabilized around 280° F in mid-1998 and has increased only slightly to about 300° F since then. The "hot" interval, as recorded in January 2000, has broadened slightly over the last year and is now 74 ft thick. However, in contrast to the other three temperature observation wells, this "hot" interval is 45 ft below the top of the Monarch Sand, which is the standoff interval of the top of the injection points in the nearby injector well (Pru I2-4). In May 2000 this injector received a workover to seal the lower four existing perforations and raise the injection interval by 66 ft.

It is interesting to observe that the temperature peaks for all wells, except TO-4, tend to shift downward through time. This suggests that the steam chest, once having been restricted by the less permeable strata overlying the Monarch Sand, then builds downward.

The temperature observation wells record two separate aspects of the build up of heat within the Monarch Sand reservoir: (1) variations as a function of distance outward from the injector and (2) spatial variations in the capacity of the reservoir to transmit steam and advective heat. In terms of heating at the site of the temperature observation wells, the wells fall into two groups. The TO-3 well, just 45 ft away from an injector, reaches maximum temperature quickly through fingering of steam along stratal intervals and cools slightly as heat is transmitted into surrounding strata. For the wells more distant from the nearest injector, the heat builds rather slowly. If there are stratal controls on steam transport, they are secondary factors

In as much as the normal distance between injector and producer is in the range 150 to 200 ft, it would be reasonable to conclude that as of January 2000 the "steam chest" in the steam flood pilot was not yet fully developed. The slow building of the region of elevated temperature is very likely inhibited the full production potential of the steam flood pilot. This observation greatly influenced the decision to use considerably higher steam injection rates in the new patterns brought on-stream in January 2000.

Ambient Temperatures in the New Steam Flood Patterns

The three new temperature observation wells, drilled and logged in December 1999-January 2000, record the ambient reservoir temperature prior to the initiation of steam flood, but after nearby producers had been cycled for over a year. The temperature logs (Fig. 4-9) illustrate the importance of factoring prior thermal recovery activity into the design of a steam flood project. The TO-6 well in the southwest corner of the Pru Fee property shows only slight heating in the upper part of the Monarch Sand. The maximum temperature recorded is just 114.0° F. In contrast, the two temperature observations wells along the upper edge of the property, adjacent to the active Nevada lease, record thick intervals where the temperatures exceed 200° F. At the location of the TO-5 well near the northwest corner of the property (pattern 10), the upper 130 ft of the Monarch Sand is hotter than 200° F and the maximum temperature recorded is 262.7° F. The TO-7 well in the extreme north-central portion of the property (pattern 12) records temperatures in excess of 200° F in the top 215 ft of the Monarch Sand. There are two temperature maxima at 57 ft and 189 ft below the top of the Monarch Sand, 255.6° F and 258.6° F, respectively. The multiple temperature peaks recorded in both of the northern temperature observation wells suggests that "fingering" of steam within discrete strata-bound zones continues to control heat within the reservoir. The broad injection intervalin the Nevada lease injectors to the north is an important factor in the thick steam chest observed. These portions of the Monarch Sand reservoir appear to be deeper stratigraphic intervals than those penetrated by wells in the four-pattern pilot.

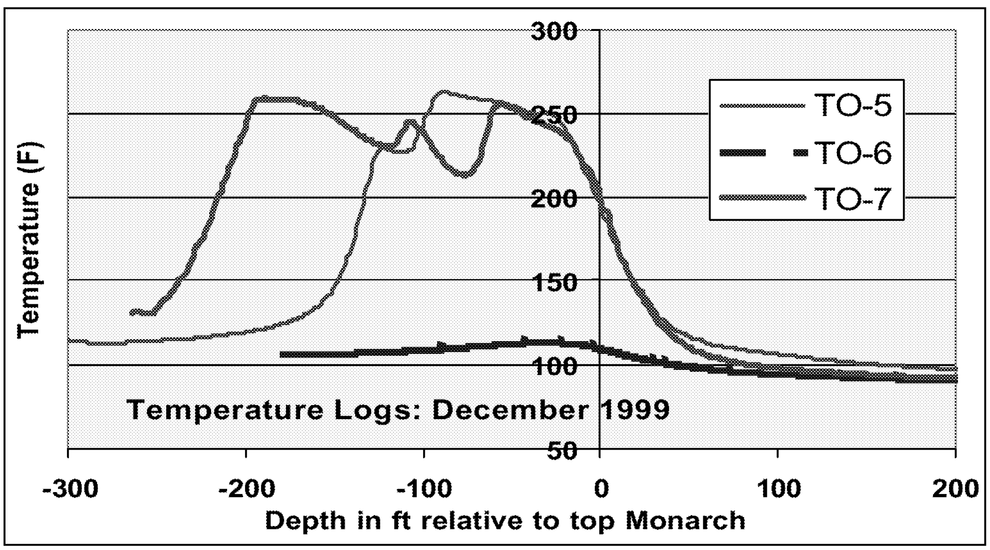


Figure 4-6: Temperature logs for the new temperature observation wells on the Pru Fee property.

Heat Buildup Associated with Total Steam Flood Operations

With the conversion of the "300-series" cyclic producers to steam flood in January 2000 the rates of steam injection on the Pru Fee property as a whole have increased substantially. The response in each of the temperature observation wells is shown in Figures 4-10 through 4-16. The effect is only in part to increase the reservoir temperature. More generally one observes a broadening and "homogenization" of the temperature profile as a consequence of the continued steam flood operations. The influence of the "middle barrier" unit within the area of the pilot is well demonstrated. In TO-1 and TO-2 steam appears to be slipping in under the barrier unit to heat lower strata that prior to January 2000 were relatively cool (Figs. 4-10 and 4-11). This steam may be coming from new injectors, such as Pru I2-8 and Pru I2-9, that are perforated deeper than those in the pilot. In TO-3 and TO-4 the barrier unit appears to serve as the lower limit for reservoir heating (Figs. 4-12 and 4-13), preventing steam from entering deeper sand intervals. TO-5 and TO-7 lie outside of the region with the barrier unit, yet show the possible effects of other stratigraphic horizons on the slightly rising temperature profile (Figs. 4-14 and 4-15). Interestingly, TO-6 (Fig. 4-16) has show no increase in temperature during over more than a year of steam injection into the nearby Pru I2-6 and Pru I2-7 injectors. The reason for the sluggish response is unknown.

All of the recent logs indicate that the temperatures at the top of the Monarch Sand are in the target range of 200° to 250° F.

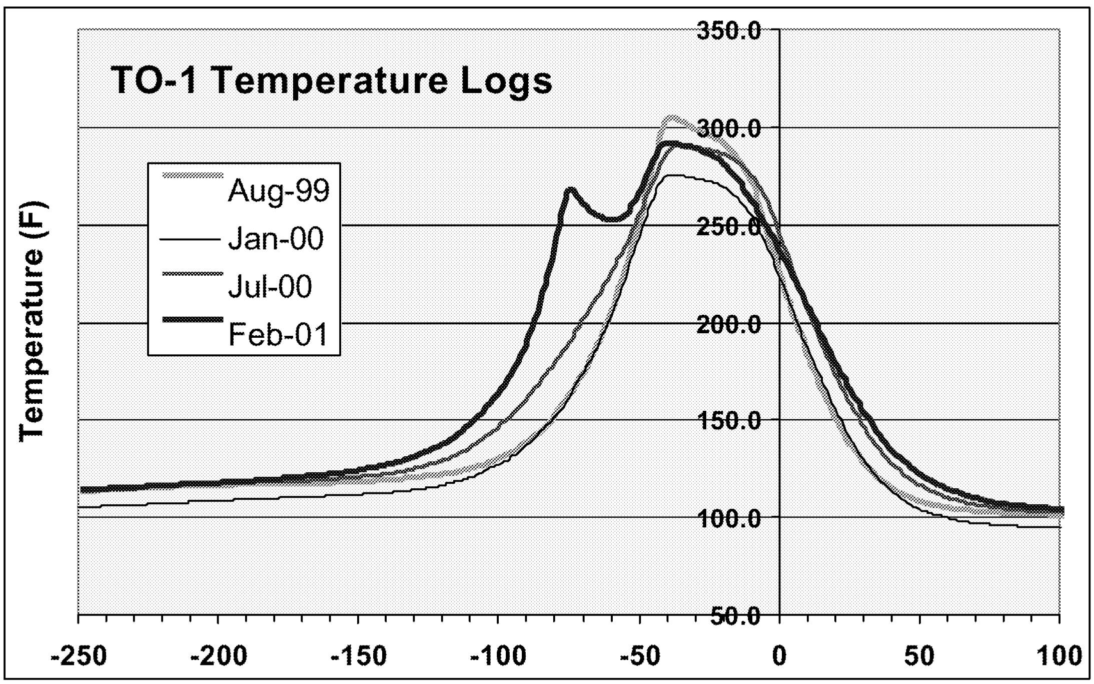


Figure 4-10: Temperature logs for the TO-1 well near the center of the Pru Fee property. At this location the "middle barrier" unit is 76 to 88 ft below the top of the Monarch Sand, which serves as the datum in this and the following log plots.

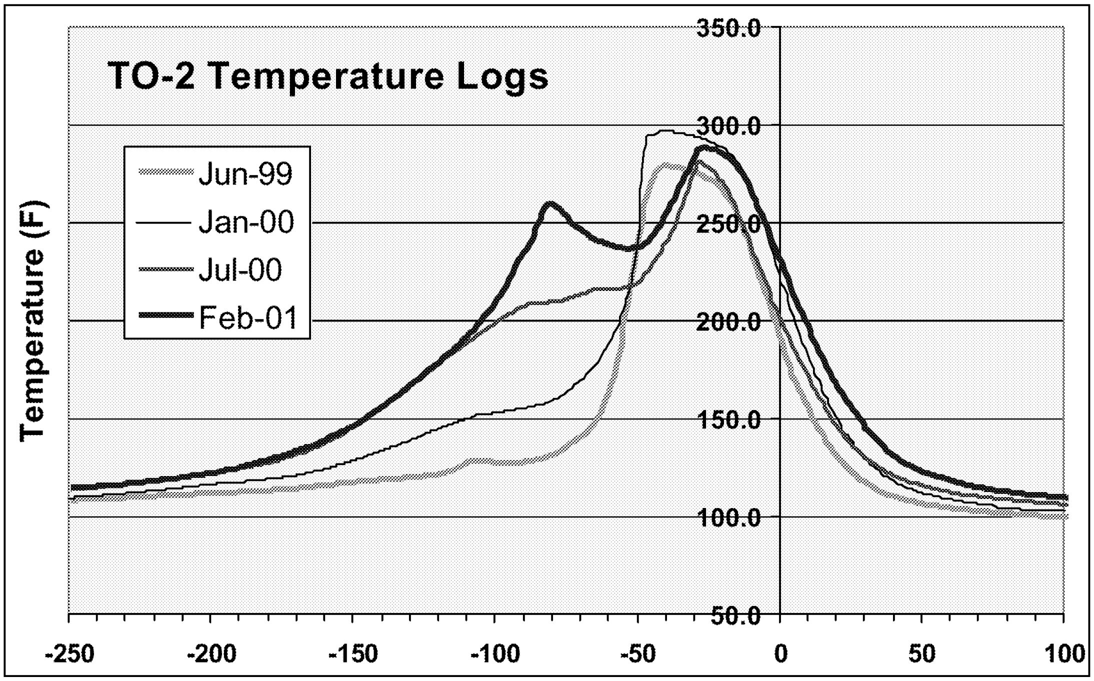


Figure 4-11: Temperature logs for the TO-2 well in the NW pattern of the Pru Fee pilot. At this location the "middle barrier" unit is 49 to 57 ft below the top of the Monarch Sand and is clearly influencing the distribution of steam after Janauary 2000.

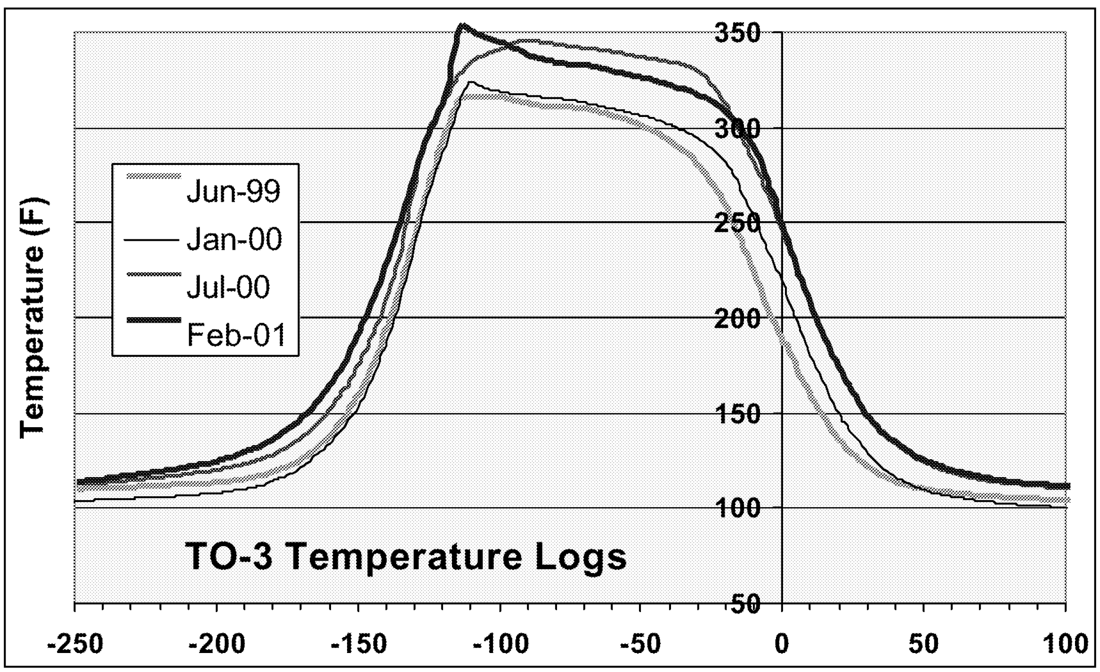


Figure 4-12: Temperature logs for the TO-3 well in the SW pattern of the Pru Fee pilot. At this location the "middle barrier" unit is 107 to 123 ft below the top of the Monarch Sand and is apparently controlling the base of the "hot" interval.

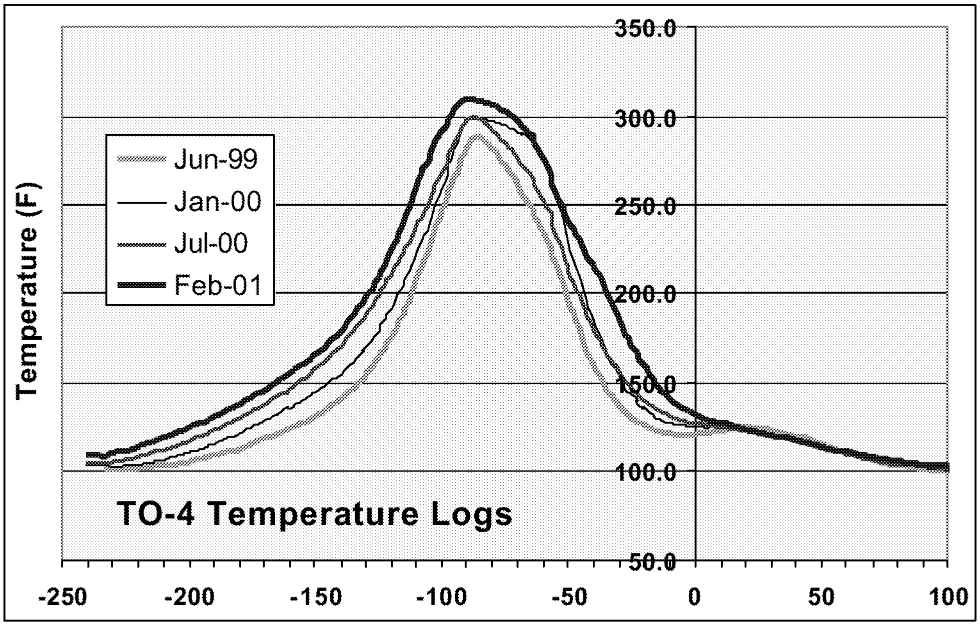


Figure 4-13: Temperature logs for the TO-4 well in the SE pattern of the Pru Fee pilot. At this location the "middle barrier" unit is 114 to 123 ft below the top of the Monarch Sand and may be influencing the location of the base of the "hot" interval. The injection points in the nearby Pru I2-4 injector are deeper than in other wells in the pilot, but the entire string of injection points was raised by about 20 ft in May 2000. This may account for the symmetric broadening of the temperature profiles through time.

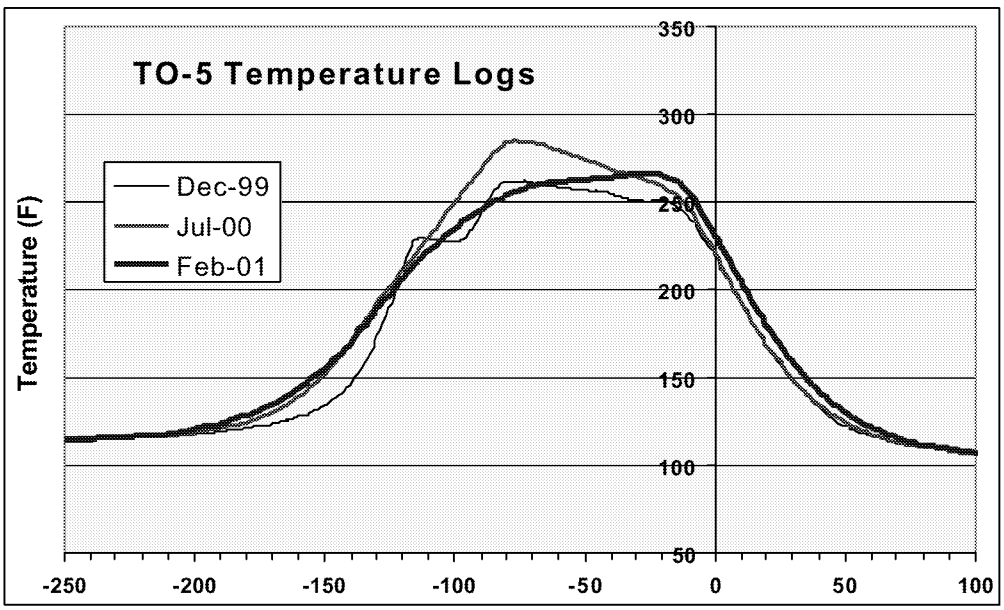


Figure 4-14: Temperature logs for the TO-5 well in pattern 10 near the NW corner of the Pru Fee property. At this location the "middle barrier" unit is absent. This well is clearly showing the influence of heating by thermal recovery operations in the nearby Kendon lease.

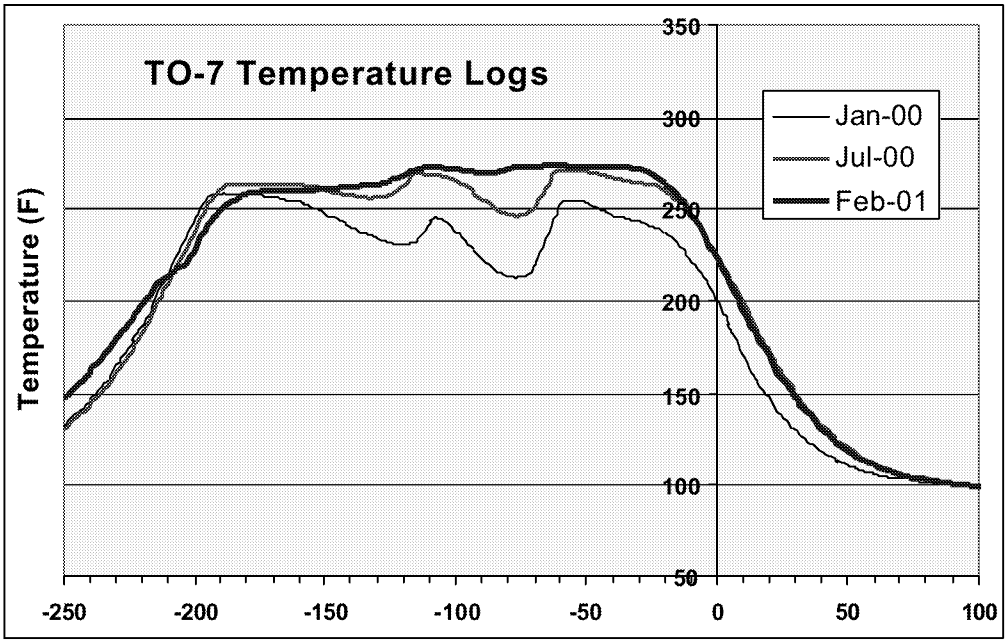


Figure 4-15: Temperature logs for the TO-6 well in pattern 7 near the SW corner of the Pru Fee property. This well is in a very cool part of the Monarch Sand reservoir and is showing sluggish response to steam injection in nearby injectors.

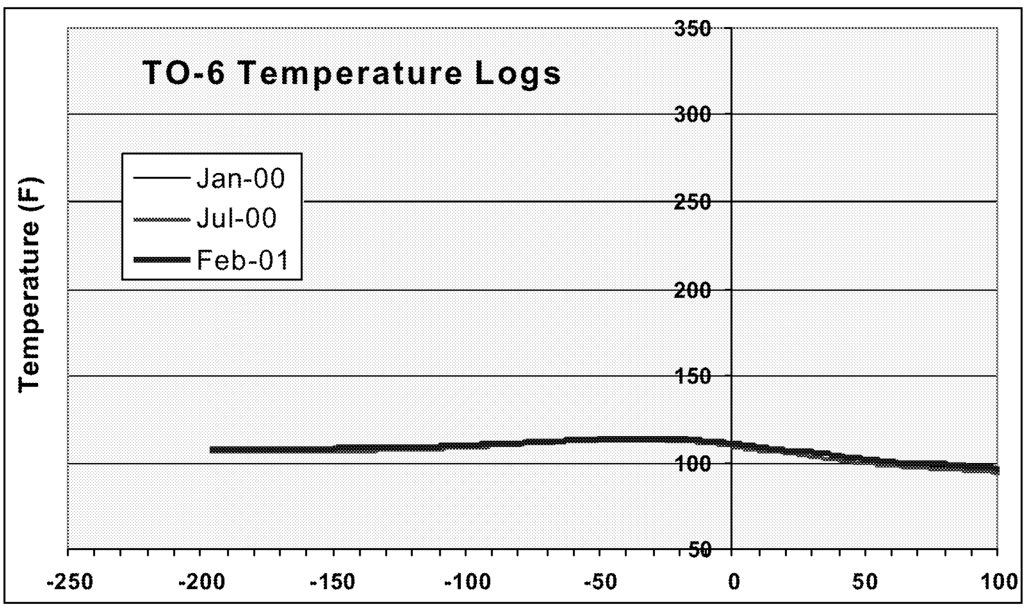


Figure 4-16: Temperature logs for the TO-7 well in pattern 12 near the north-central edge of the Pru Fee property. At this location the "middle barrier" unit is absent. This well is clearly showing the influence of heating by thermal recovery operations in the nearby Nevada lease. Note how through time the stratigraphically "fingered" temperature profile is smoothed out by small-scale heat advection and conduction.

Temperature of Produced Fluids

An additional method for monitoring the ambient temperature of the Monarch Sand reservoir is to track the temperature of produced fluids. These fluid temperatures for the Pru Fee pilot through the entire duration of the project are plotted in Figure 4-6.

The first temperature spike in produced fluids relates to cyclic production of a group of renovated wells serving as a general baseline for subsequent steam flood production. Once the entire steam flood pilot came on-line in the first quarter of 1997, there has been a steady increase in the temperature of produced fluids. The temporary plateaus relate to times when steam injection rates were dropped back to a base level 1200-1300 bspd rate. The surge in temperature observed in the last two quarters of 1999 relates to the considerably higher steam injection rates (up to 2,285 bspd) being used in the pilot with the intention of more quickly driving up the reservoir temperature. These produced fluid temperatures were not reported for the first two quarters of 2000. In as much as the fluids experience some cooling rising up the well, the temperatures will be somewhat less than the average in situ reservoir temperature. However, they do confirm that through the end of 1999 the reservoir temperature had continued to rise.

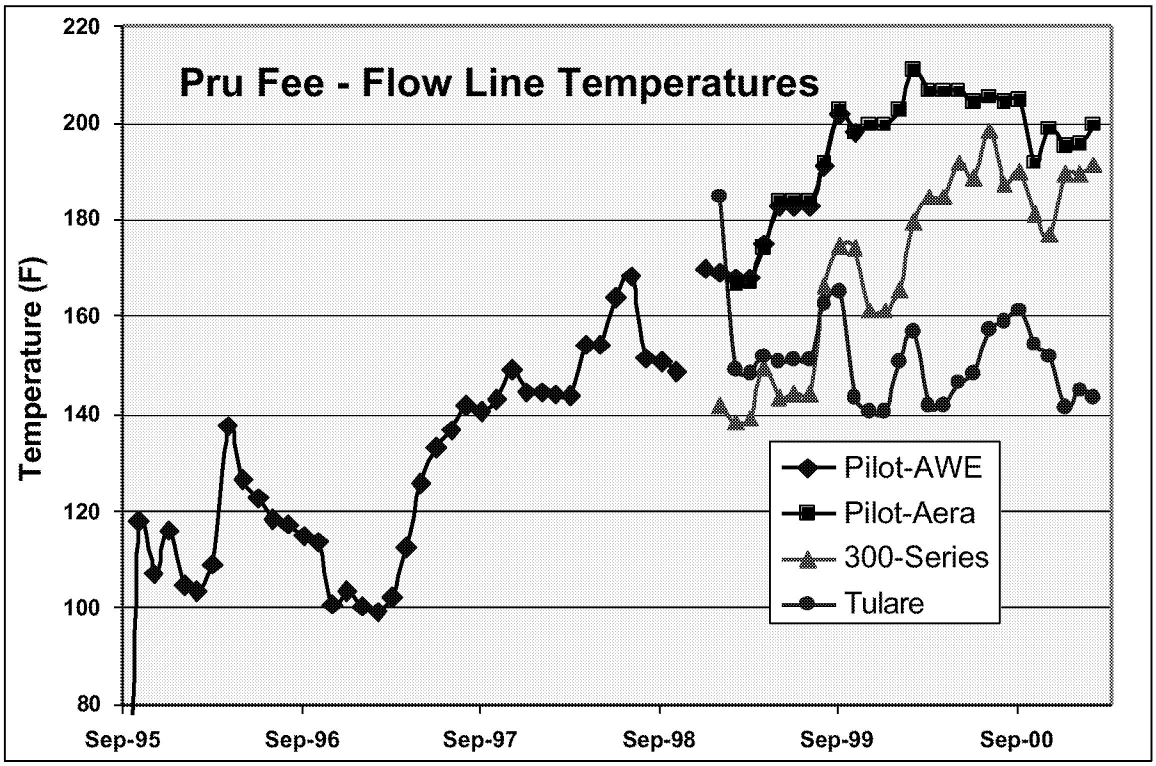


Figure 4-17: Temperature of produced fluids (water and oil) from the four-pattern steam flood pilot showing the gradual increase in reservoir temperature since the onset of the steam flood operation in the second quarter of 1997. The break in December 1998 is related to the change of operator and installation of a different metering line.

Chapter 5

Simulation of Production Performance

Introduction

Pru Fee, a property that was extensively studied in the course of this project, was shut-in in 1986 with an estimated 85% of the original oil in place unrecovered after was not responsive to the cyclic steam process. Four producibility problems tentatively were identified at this property: shallow dip, reservoir heterogeneity, thinning pay zone and the presence of bottom water.

The reservoir simulation study described in this chapter was conducted in three phases:

Phase 1: In this phase, a series of generic, two-dimensional simulations were performed to evaluate the relative importance of the four factors enumerated above. These were a set of sensitivity studies.

Phase 2: A series of three-dimensional simulations were performed to develop an early process strategy. The process of choice was steam flooding, with occasional stimulation of producers. The geologic model used in this study, for the most part, was based data from a single new well drilled on the property. Only a quarter of a single two-acre nine-spot pattern was simulated.

Phase 3: The geologic model was refined to include data from all of the project wells drilled and logged through early 2000. Simulations were performed on just two of the two-acre, nine-spot patterns in the initial four-pattern project pilot near the center of the Pru Fee property. The patterns simulated are those in the NE (pattern 2) and the SE (pattern 4) of the pilot.

Reservoir models were constructed using Heresim3D™, a Geomath-IFP product, while all of the simulations were performed using STARS (Steam and Additives Reservoir Simulator) developed by the Computer Modeling Group Inc.

Initial Production Simulations

Two-dimensional Simulations (Phase 1)

Initial simulations were performed in 1996 using two-dimensional models that approximated the reservoir stratigraphy as determined in existing well logs. Several different two-dimensional models were used and specific reservoir features were studied. Three different thermal processes were examined:

1) Cyclic steam stimulation - a specific example in which two weeks of injection is followed by a week of soak and a production duration of 20 weeks. Each well serves alternatively as an injector and a producer.
2) Steam flooding - in which steam is continuously injected into the reservoir in injector wells and reservoir fluids are removed by the surrounding producer wells.
3) Cyclic flooding - where the steam flooding process is interrupted periodically by cyclic stimulation of the producers. This process is commonly employed in the field to eliminate production problems in producers and to establish effective communication between injectors and producers.

The initial simulations revealed that for the Monarch Sand at Pru Fee the performance of the steam flood and the cyclic flood processes were superior to the cyclic steam stimulation process. Due to better reservoir sweep, recoveries in the two food processes were 20-25% better than in the cyclic process. However, oil-steam ratios were slightly better in the cyclic process (0.15) compared to the steam flooding process (0.11).

An initial investigation of the completion strategies clearly showed that, in an ideal reservoir, completing the injector in the bottom third and the producer over the entire production interval is the best strategy. The study was performed without bottom-water present. This completion is practiced almost universally in the Midway Sunset field, and served as the base case in three-dimensional simulations.

The simulation study of reservoir dip showed that for the stratigraphic dip of the Monarch Sand at Pru Fee (10° to 15°) relative locations of the injectors or producers with respect to the dip would not affect production performance significantly.

Two-dimensional simulations also showed that bottom-water had a strong effect on production performance. When a thick water zone was employed, it was established that there was an optimal length for the injector completion above the oil water contact to maximize production. This concept was investigated further in 3-D simulations.

Examination of the effect of the presence of low-permeability barriers in the reservoir showed that there was noticeable impact on oil production, if the permeability of the 'barriers' were two orders of magnitude lower than the permeability of the high-permeability zones.

3D Simulations Based on PRU-101 Core Analysis Data (Phase 2)

The initial reservoir models for simulations were generated by the stratigraphic and geostatistical modeling group based primarily on petrophysical analyses from the Pru-101 core. Heresim3D^{TM}, a geologic and geostatistical modeling tool, was used to develop the models. The petrophysical properties for the three-dimensional models were determined for a domain that surrounded Pru Fee and contained data from Pru-101, and from wells drilled in adjacent leases. Probability distribution functions that reflect the character of permeability and porosity within each lithotype were estimated using data derived from log and core data from Pru-101. Spatial distributions of porosity and permeability were established using variograms and vertical proportion curves, a unique feature of

Heresim3D^{TM} that allows the vertical variation of lithotypes to be distributed through the reservoir model volume. An initial reservoir model had blocks of dimensions 30 feet by 30 feet horizontal and a total of 220 layers distributed through 300 feet average sand thickness. Heresim3D^{TM} used an indicator, geostatistical approach, whereby lithofacies were assigned to individual blocks followed by porosity, permeability assignments. Each reservoir model created is one of a series of equiprobable realizations. The reservoir geostatistical model was up-scaled to contain just 20 layers and the same horizontal cell dimensions. To simplify the simulation, just a small symmetric element of the reservoir model was used in the simulations. The element employed in all these simulations is one quarter of a single two-acre nine spot (a half-acre symmetry element) with the Pru-101 well forming the NW corner. Details of model design are presented in Hongmei (1998).

Each of the three thermal processes - cyclic, steam flood and cyclic flood - was studied using the 3-D model. The steam flood and the cyclic steam flood yielded similar recoveries and oil-to-steam ratios (OSR), while the cyclic process was clearly less efficient. The modeled ten-year recoveries from cyclic flood and the steam flood processes were about 25% of the original oil-in-place with cumulative OSR values of about 0.15. The OSR in the cyclic process was about the same while recoveries were in the 20% range. Pattern studied revealed that there were no significant differences between the five-spot and the nine-spot patterns. Well completion investigations showed that it was most beneficial to complete the injectors 70-90 feet above the oil-water contact. Finally, it was demonstrated that an injection rate of about 1 bbl/acre-foot was reasonable in terms of expediently recovering the oil and the OSR values.

Simulations Based on the Full Suite of Logged Wells in the Pilot

Generation of the Pilot Reservoir Model (Phase 3)

Obtaining the input parameters needed for fluid flow simulations requires that the three-dimensional distribution of petrophysical properties be estimated throughout the simulation volume. To this end, a series of petrophysical models were developed for the Monarch Sand at Pru Fee using Heresim3D^{TM}. Developed by the Institute Francais du Petrole (IFP) and collaborators (ARMINES and BEICIP-FRANLAB) and distributed in the United States by Geomath, Heresim3D^{TM} is specifically designed to build integrated reservoir models. Geophysical logs from 39 wells provided the basis to estimate the spatial distribution of facies type, permeability, porosity and water saturation. Well locations at Pru Fee are shown in Figure 1.

After entering the petrophysical data derived from the well locations into Heresim3D^{TM}, the domain that surrounds the reservoir simulation volume was constructed. Six surfaces, three actual stratigraphic, the oil water contact (OWC) and two model surfaces, were identified to demarcate different units in the reservoir. The top surface was roughly 20 feet above the top of the Monarch formation and the bottom surface was roughly 20 feet below the oil-water contact. The geologic significance of the middle stratigraphic unit has been discussed elsewhere in the report. This unit was preserved in the reservoir description for simulation and was titled the *middle barrier*. The surfaces are (numbered accordingly in the model):

1. A surface 20 feet above the top of the monarch
2. Top of the Monarch (unconformity)
3. Top of the middle barrier (unconformity)
4. Bottom of the middle barrier
5. The oil-water contact
6. A surface 20 feet below the oil-water contact

Contour maps of the top of the Monarch Sand and of the oil-water contact are shown in Figures 2 and 3. To depict the reservoir geometry, two cross sections were constructed; the northwest-southeast cross section (Figure 4) and a northeast-southwest cross section (Figure 5). The six surfaces that describe the reservoir are shown in the NW-SE cross section in Figure 6 and in the NE-SW cross section in Figure 7. It is observed that the top of the Monarch Sand dips toward the Southeast providing a thinner pay zone in that direction.

During geological analysis of the reservoir data, it became apparent that the middle barrier separated the reservoir into two major stratigraphic units (here called 'lithounits'), while the middle barrier itself forms a third lithounit. These lithounits are titled the ‘upper’, ‘middle’ and ‘lower’ lithounits. Separate petrophysical models were computed for the three lithounits. Prior to the construction of the lithounit models, the modeling grid was defined. The modeling grid (aerial view) is shown in Figure 8.

Petrophysical models were computed using a three-dimensional gridded volume with $\Delta x = \Delta y = 60$ ft and $\Delta z = 5$ ft. The number of cells in the x and the y direction were 60 each and 100 in the z direction. For vertical gridding, two approaches were used. In the upper and the lower lithounits, parallel gridding was used and proportional gridding was employed in the middle zone. In parallel gridding, grids are constructed parallel to a reference layer, within a lithounit. In proportional gridding, layers are "parallel" to both the bottom and the top of the unit. While gridding the upper unit, surface 3, (top of the middle barrier or base of the upper unit), is taken as the reference surface to construct a parallel grid and similarly in the lower unit, surface 4, (bottom of the middle barrier), was considered taken as the reference surface. The middle unit consists of five proportional layers.

The lithofacies were designated using the porosity of the sands as shown in Table 1. It was observed in core samples from the Pru-101 well, and confirmed in other nearby Monarch Sand cores, that porosity is a reasonable predictor of sand coarseness, the measure used here for 'lithofacies', and permeability. Four lithofacies were designated. The permeability assignments were based on the 'best-fit' curve in a porosity-permeability cross-plot (Figure 9). Three type logs of how different lithofacies compare with assigned porosities are shown in Figure 10. This figure shows that the assignments capture the variations observed in logs. After the lithofacies have been assigned to the blocks, the lithofacies are assigned to lithotype. In this study, each lithofacie is assigned to a lithotype, thus creating 4 lithotypes.

Table 1: Designation of lithofacies based on porosity class.

Lithofacies	Porosity class (%)
1: Pebbly Sand	<25%
2: Coarse Sand	25-32
3: Medium Sand	32-40
4: Mudstone + Fine Sand	>40%

A vertical proportion curve (Figure 11) is a stacked bar diagram that represents the vertical distribution of the percentages of all the lithotypes found within a specific lithounit. Vertical proportion curves are very useful in capturing geological information within the geostatistical models. Though the curves can be manually adjusted in Heresim3D^{TD}, this study uses unadjusted ones. The curve for the entire unit (Figure 11) in this study shows that facies 2 and 3 dominate all the lithounits. The construction of the vertical proportion curve serves as the basis for the construction of variograms that characterize the spatial distribution of facies in the reservoir. Heresim3D^{TM} uses an indicator approach to develop a petrophysical model. First, facies distributions are interpolated throughout the 3-dimensional modeling domain. Second, permeability and porosity are assigned to individual gridblocks within each facies type using a probabilistic method. Values of permeability and porosity associated with each facies type are assigned to each gridblock using a probabilistic approach (Schamel at al., 1997). Using the lithotype statistics, the petrophysical model is built for each of the lithounits. Global univariate statistics (Schamel at al., 1997) were used in distributing, first the lithofacies followed by porosities, permeabilities and water saturations. Ky and Kz were assigned equal to Kx based on the PRU-101 core data.

Simulations were performed for each of the three lithounits. To construct the reservoir, the upper, middle and the lower units were combined. Lithofacies distributions in one horizontal slice (top lithounit, elevation 689 feet) is shown in Figure 12. It is seen that the lithofacies 2 (coarse sand) dominates the distribution. A NW-SE cross section is shown in Figure 13, once again, highlighting the preponderance of lithofacies 2. The porosity distributions over the same cross section for the top lithounit are shown in Figure 14. Porosities in the 27% to 33% range dominate this distribution. The permeability distribution is shown in Figure 15. More variation is observed in permeability; however, no significant compartmentalization is observed. It was hypothesized in earlier geologic studies (and supported by some field evidence) that the middle lithounit might be a lower permeability zone. The present geologic model does not support that. If additional information regarding presence of such a zone is available, it will have to be built into the model.

Water saturation distributions were obtained completely independent of all the other properties. Water saturation was treated as an independent petrophysical property provided by the logs. Water saturation distributions for one of the geostatistical realizations shown in Figure 16. In as much as water saturation determines the effectiveness of any thermal process undertaken, a second realization is shown in Figure 17. The difference between the two realizations is not significant.

To make the reservoir model suitable for reservoir simulation upscaling is performed inside of Heresim3D^{TM}on predetermined domains. The upscaling procedure has been described in detail in an earlier report (Schamel, et al., 1997). The upscaling domain considered in the simulations is the four-pattern pilot for the project, which consisted of four 2-acre nine-spot patterns. This area with the associated wells is shown in Figure 18. For most of the simulation studies, Pattern 2 was employed. Pattern 4 was also used for some studies. Two grids were constructed for Pattern 2; an 8 x 8 grid and the other, a more refined, 12 x 12 grid (aerial). For the first grid, $\Delta x = \Delta y = 36$ ft and for the second one, $\Delta x = \Delta y = 24$ ft. Vertical upscaling was done to assign representative values of porosity, permeability and water saturations within the 8 x 8 or the 12 x 12 grids. Thus, in each of the three lithounits, the number of layers was reduced. The number that is chosen is a trade off between preservation of the basic reservoir geology and the computational complexity, that would result from retaining large number of layers. The middle barrier, because of its thickness, was upscaled to a single layer. As a result of vertical layering, the total number of layers in this study was reduced to16. Arithmetic averaging was used to upscale porosity, permeability and water saturation. The upscaled results are shown in the Figures 19-21. In the upscaled model, the average porosity values lie in the range of about 30-33 % and the average permeability is about 3000 md. The water saturations are generally higher below the middle barrier.

Reservoir Simulation

This section describes the simulations performed using the up-scaled reservoir properties generated. Simulation of the entire 40-acre area using a thermal simulator would have been computationally intractable. Hence, Pattern 2 was chosen as the representative study area and a smaller grid was constructed to capture the 9-spot pattern of the wells. Pattern 2 was chosen because it contained PRU-101. It should be noted that the previous detailed study was based only on data from PRU-101. As a result, a 12 x 12 grid was constructed with all the 16 layers for Pattern 2.

The commercial thermal simulator, STARS (Steam and Additives Reservoir Simulator), developed by CMG (Computer Modeling Group), was used to perform all the simulations. STARS is a three-phase, multi-component reservoir simulator. It allows different grid systems such as Cartesian, cylindrical or variable depth-variable thickness. In this study, Cartesian coordinates, allowing the use of variable thickness-variable depth, were used. The keyword input system of STARS allows the user to input the necessary information for simulation and to control the output information. Different numerical methods and control parameters can be selected to improve the computation/convergence and to accelerate the simulation.

The average porosities, oil saturations and the original oil in place in the two geostatistical realizations are shown in Table 2. There is negligible difference in properties between the two realizations. There is also substantial amount of oil in place (over 300,000 barrels per acre); however, it is associated with significant amount of water. Hence production from the property is challenging.

Table 2: Average reservoir properties from two Heresim3D™ realizations

Realization	Porosity	Oil saturation	Oil in place
First	0.350	0.420	674,000 barrels
Second	0.351	0.418	679,000 barrels

In the base case for simulation studies of Pattern 2, the initial reservoir temperature was assumed to be 100^0 F and the steam injection rate was set at 300 bbl/day. A timetable was specified to account for the cycling of the wells. A set of simulations was initially performed at this base case for a period of five years (simulation end date: September 2000). The oil rate comparison is shown in Figure 22. The simulator underpredicts the rate over most of the time interval simulated. Predictions with respect to the water rates are better (Figure 23). The cumulative oil production comparison is shown in Figure 24. The actual field response is quick and even though the later rates from the simulation are comparable to the field rates, the field production leads the simulated production on a consistent basis. This initial quick response in the field was difficult to reproduce in simulations. The OSR are compared in Figure 25. The field OSR values are consistently higher as the oil rates are under-predicted in the model and the steam injection rates are well matched in the simulations with historic rates.

The oil production under-prediction is also reflected in the prediction of the performance of individual wells (Figure 26). The actual oil production is consistently better than the predicted values. This was true for most of the production wells from the pattern.

Sensitivity of the results to the use of different geostatistical realizations was investigated. Recoveries from both the simulations were almost identical (0.08 to 0.0806 OOIP) and the oil rate plots were almost identical.

Simulations with Pattern 4 resulted in similar trends. The cumulative oil production plot for Pattern 4 is shown in Figure 27. The simulation consistently underpredicts oil production from the pattern.

Several possible reasons for the discrepancy between actual and simulated values are considered.

- The initial reservoir temperature was actually higher than the 100^0F uniform temperature that was assumed. This is equivalent to postulating that as the flooding was ongoing additional heat was coming into the pattern from other sources, most notably from surrounding leases where mature floods were already underway.
- The oil saturation was higher than what was projected via geostatistical interpolation of the logged water saturations.
- The relative permeabilities were uncertain and the actual relative permeabilities favored greater oil production and the same water production.
- There was compartmentalization within the reservoir, which resulted in a quick response and better OSR values presently. In the long term however, such a compartmentalization would decrease eventual oil recovery.

- Modeling the initial oil production response was challenging. The conventional viscosity-temperature curve may not have been very accurate. The initial temperature may have been nonuniform, causing additional difficulties in accurate predictions.

In order to examine the first postulate an initial temperature of 150^0F was assumed. With all other conditions assumed constant, simulations were performed for Pattern 2. The oil rate prediction improved significantly with this change (Figure 28) and the cumulative oil production was perfectly matched (Figure 29). It was observed however, that the later oil rates were too high (Figure 28). It is possible that there are pockets of higher temperatures in the reservoir (not as high as 150^0F), and in addition, the pattern is receiving additional heat from surrounding leases.

In the sensitivity studies undertaken, four cases were considered.

- In light of the importance of injection intervals identified from previous studies, injection into two different injection intervals was considered.
- Sensitivity to injection rates was examined.
- Changing injection rates in the middle of the project was evaluated.
- Extended predictions using the base case numbers were made.

Extending the injection from layers 10-12 (base case) to 8-13 did not yield much difference. The oil rates tracked more or less over the entire interval (Figure 30).

Two different injection rates were studied. The base case injection rate was 300 bbl/day, and was compared to an injection rate of 200 bbl/day. The oil rates with the higher rate were significantly better than the lower rates (Figure 31). However, the OSR, in later project years was better with the lower rate (Figure 32). Thus, choice of the optimal rate would depend on the economic model pertinent to the project. When the rate is lowered in the course of the project, the oil rate drops correspondingly (Figure 33). Extended predictions revealed that a rate of 30 bbl/day is maintained at the Pattern, for an effective OSR of 0.1 until 2005 (Figure 34).

Summary of Simulations

There is significant amount of oil in place at the site (over 300,000 bbls/acre), but it is associated with more than equal volume of water. The geologic model constructed using all of the logged wells at the site was rather homogeneous. Pattern based simulations were performed. The model predictions underpredicted oil rates and consequently the oil-steam ratios (OSR). Several possible hypotheses for this mismatch were identified. One of the hypotheses was higher initial temperatures and heat migration from adjacent patterns. This was tested by assuming higher initial reservoir temperature. The test resulted in a much closer match with the field data. The injection interval sensitivity study did not reveal the injection interval dependence, which was identified, in the previous study where a limited geological input was available. Extended predictions showed that steady oil recovery is attainable at an OSR between 0.1 and 0.2. Rate of 300 bbl/day was reasonable. Lowering the rate decreased oil rates, but improved OSR.

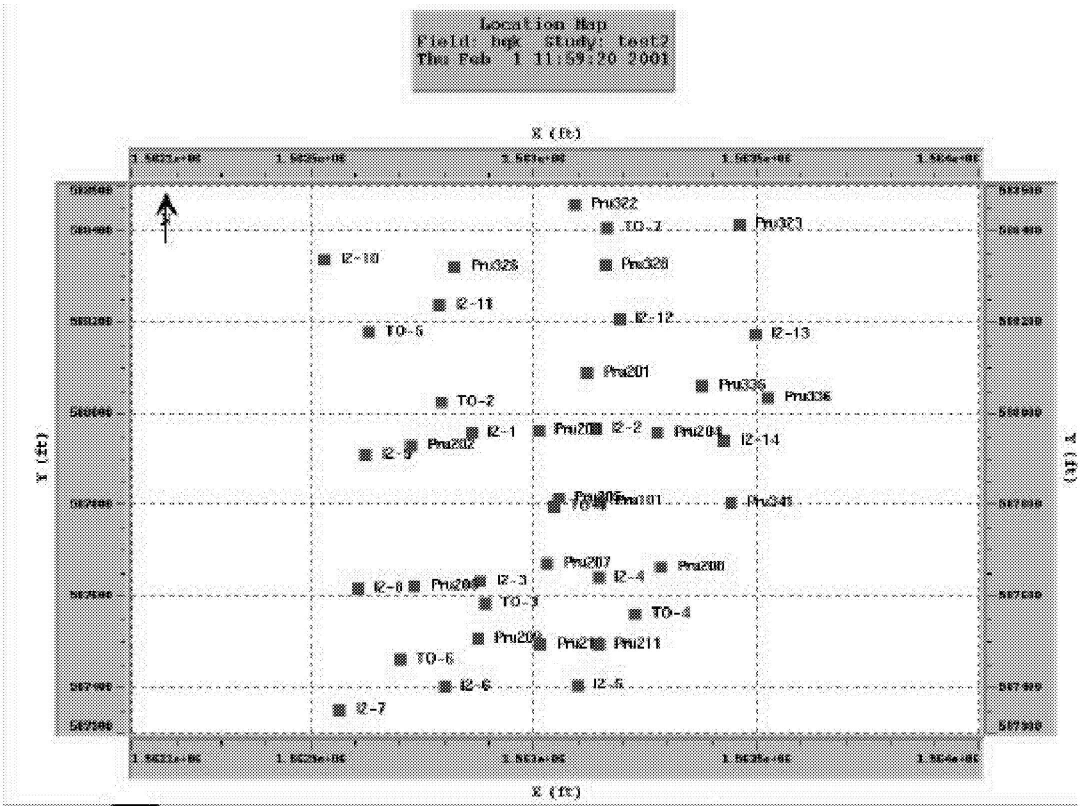


Figure 5-1: Heresim3D base map of the Pru Fee property showing top-reservoir locations of the wells used in geostatistical modeling of the Monarch Sand reservoir.

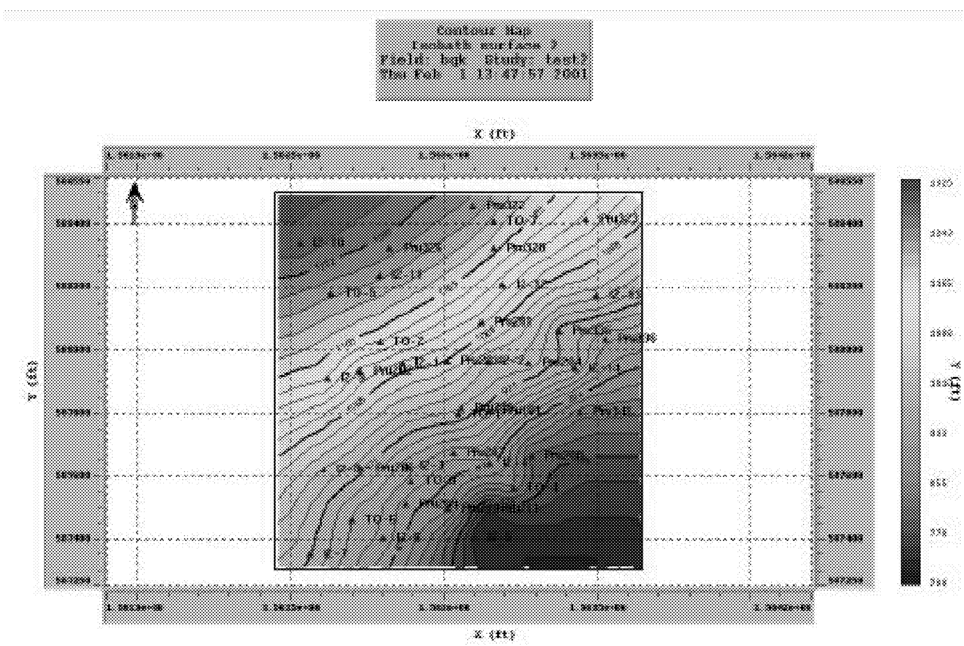


Figure 5-2: Contour map of the top of the Monarch Sand reservoir (feet msl).

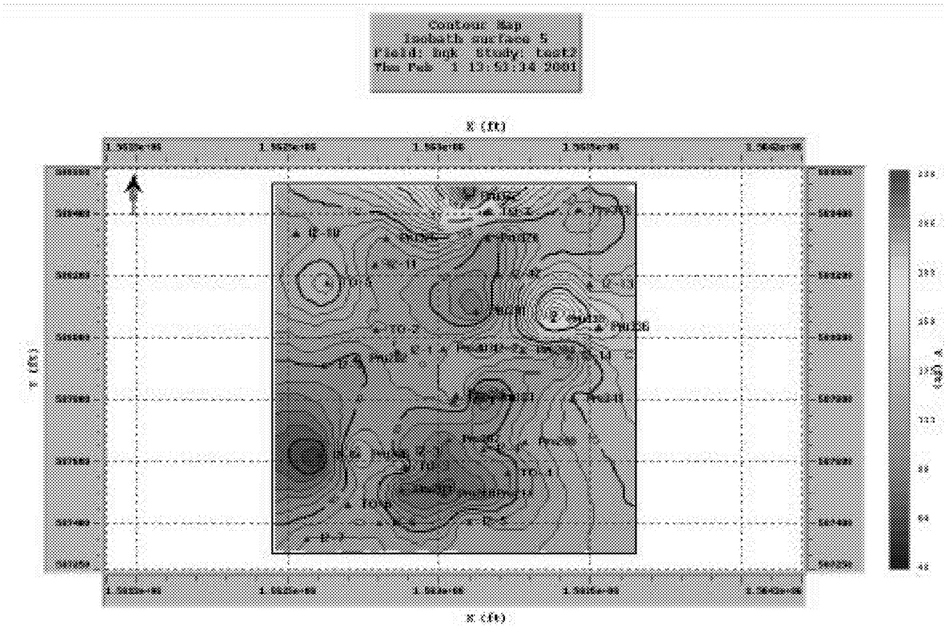


Figure 5-3: Contour map of the oil-water contact elevation in feet msl.

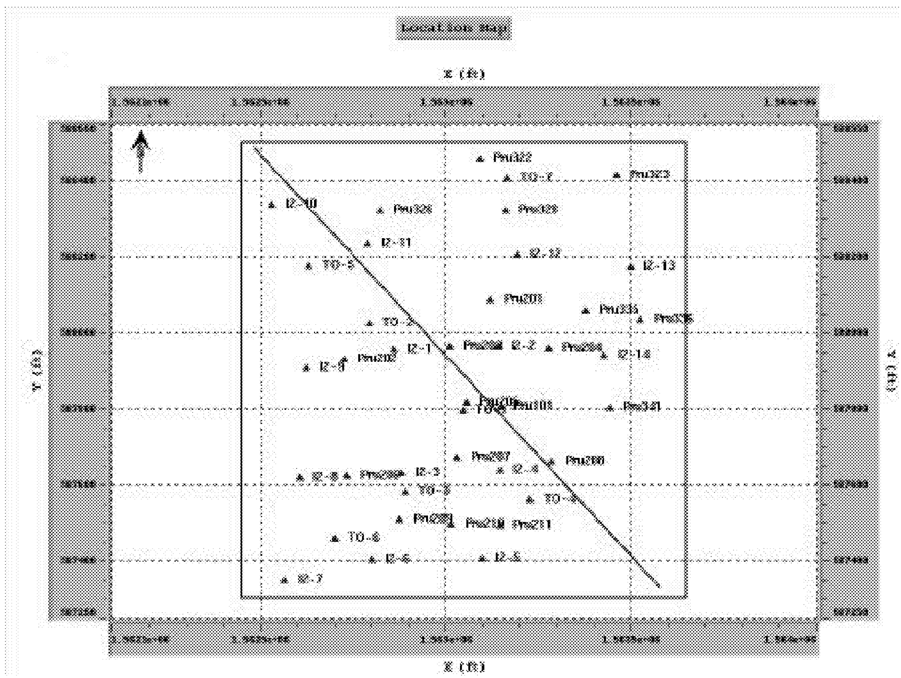


Figure 5-4: Location of the northwest-southeast model cross section through the Monarch Sand reservoir at the Pru Fee property.

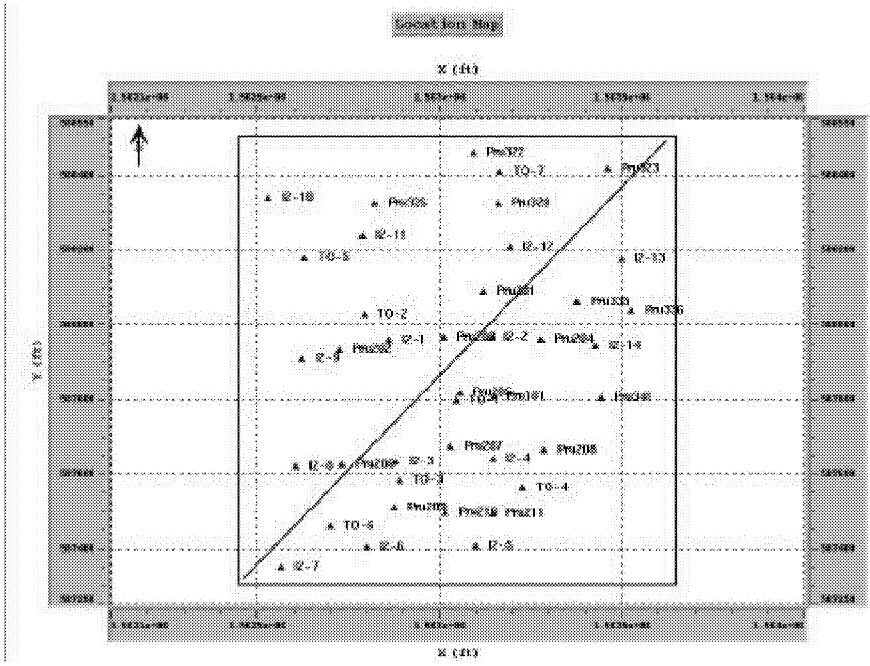


Figure 5-5: Location of the northeast-southwest model cross section through the Monarch Sand reservoir at the Pru Fee property

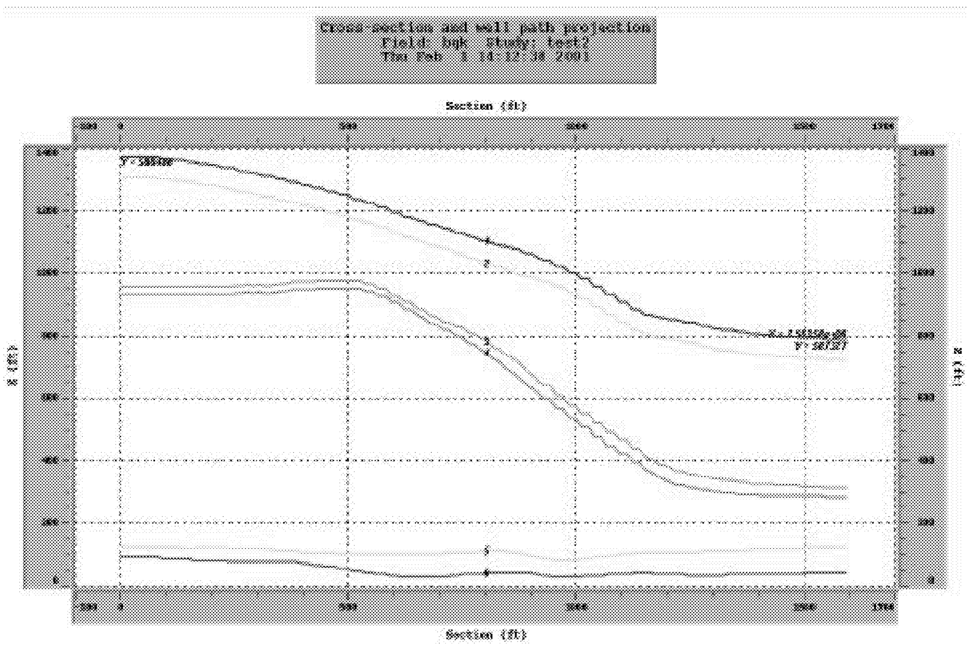


Figure 5-6: The NW-SE structure cross section showing the various stratigraphic surfaces incorporated into the geostatistical model.

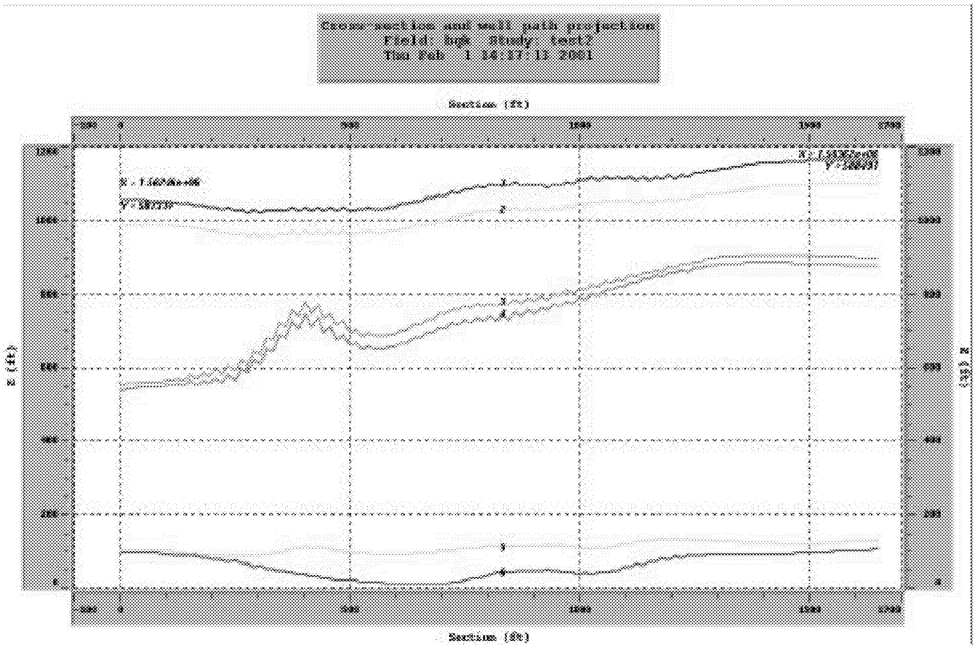


Figure 5-7: The NE-SW structure cross section showing the various stratigraphic surfaces incorporated into the geostatistical model.

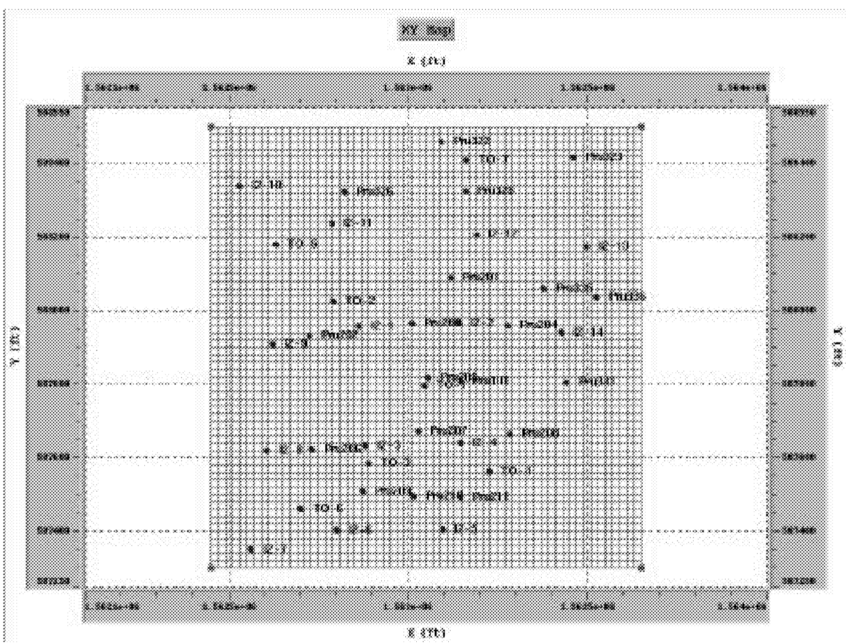


Figure 5-8: Map of the Pru Fee area showing the base grid for the geostatistical model and the location of wells incorporated into the model.

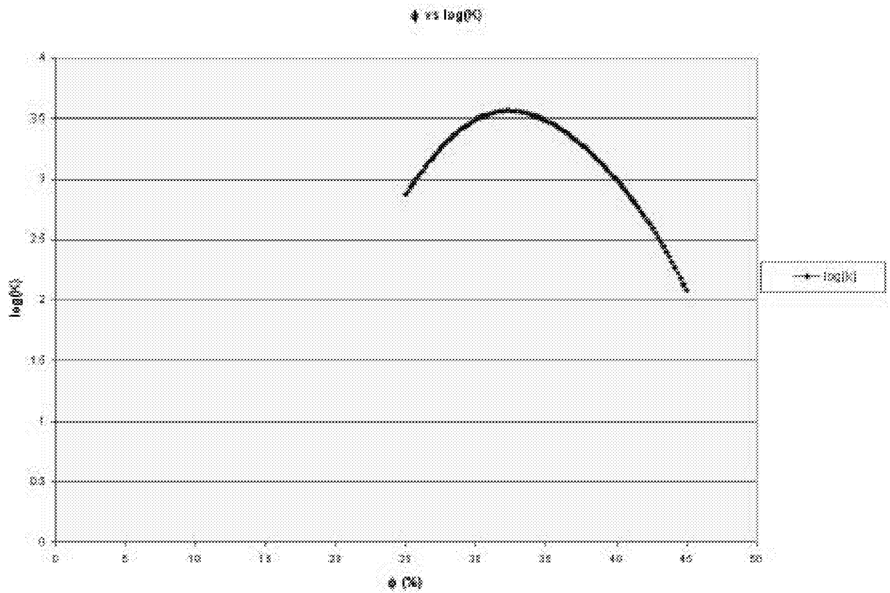


Figure 5-9: The averaged relationship between porosity and permeability in the Monarch Sand reservoir based on measured values in core samples in the Pru-101 well. Sands with porosity in the 30-38% range has permeability greater than sands with higher or lower porosity. This aspect of the petrophysics is discussed in Chapter 3.

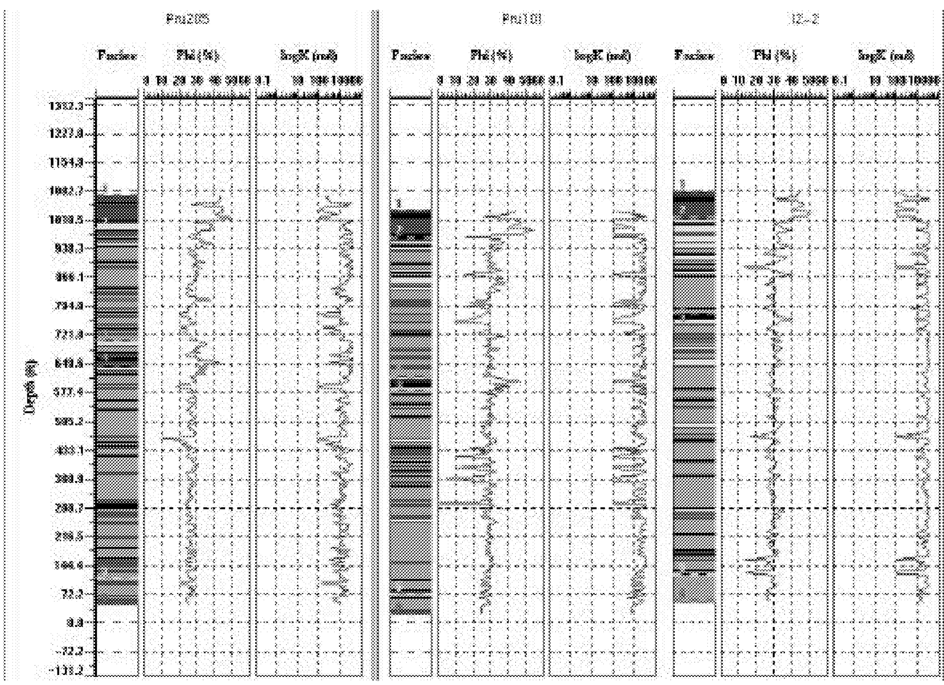


Figure 5-10: Representative well logs showing how different facies designations compare with log porosity and permeability assigned from the curve values of Figure 5-9.

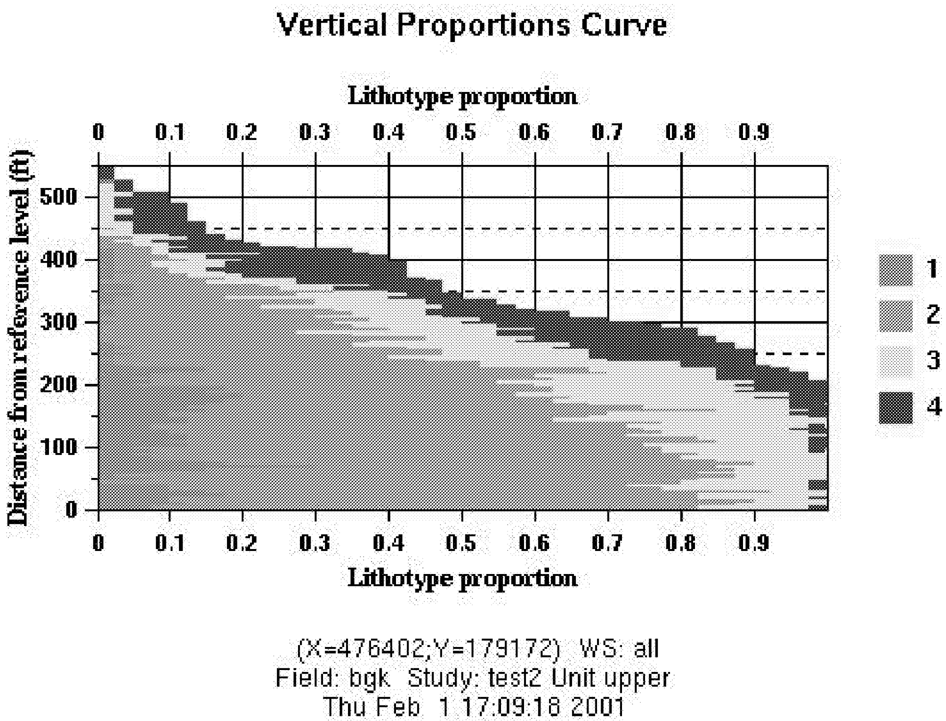


Figure 5-11: Vertical proportion curve indicating the relative abundance of each of the lithotypes.

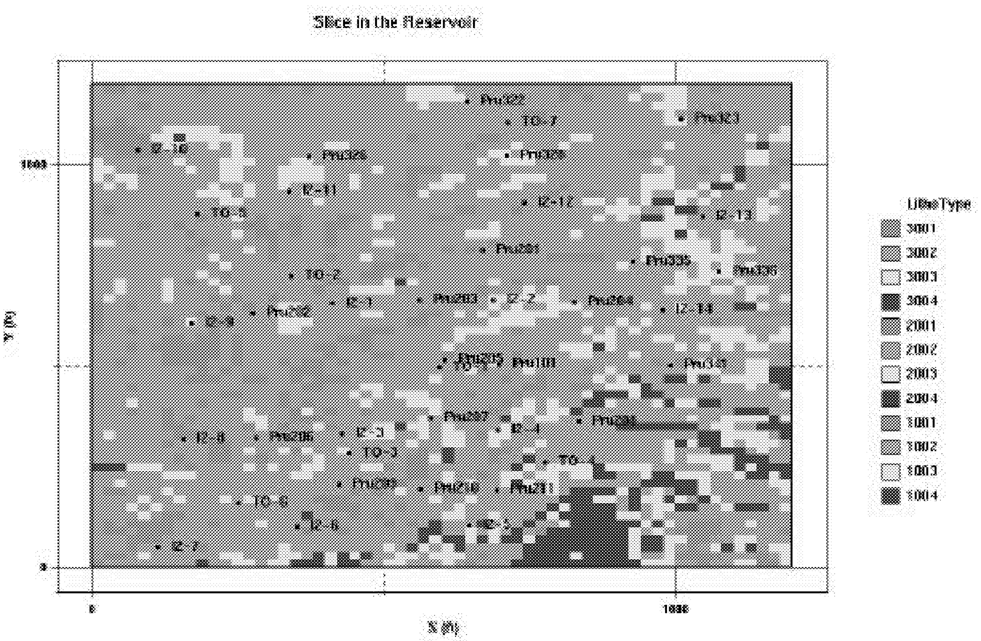


Figure 5-12: A horizontal section through the reservoir showing lithofacies distribution.

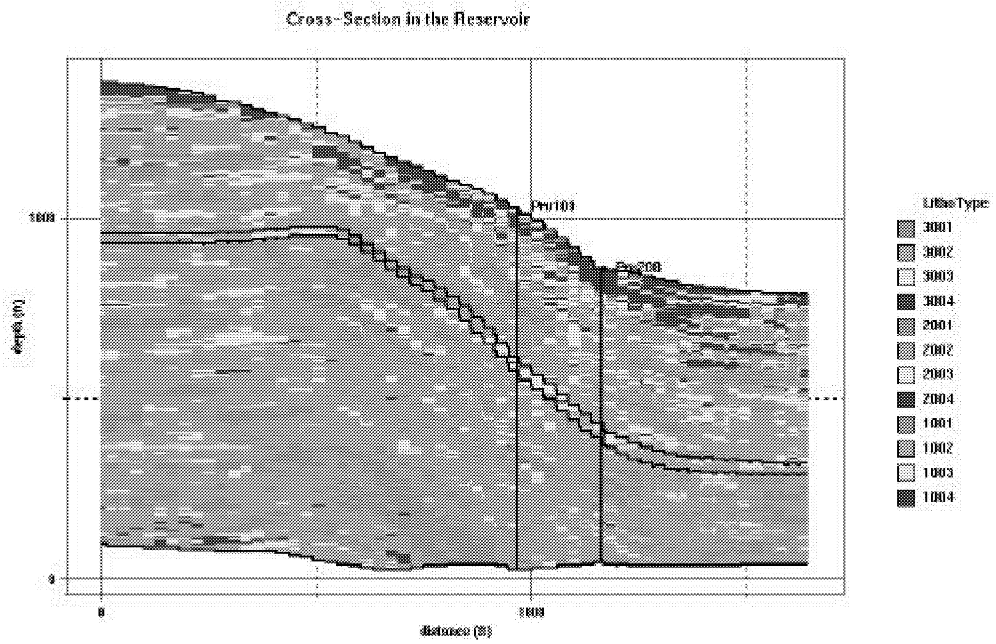


Figure 5-13: Lithofacies distribution in the Monarch Sand in the NW-SE cross section when all the three lithounits are combined into a single reservoir.

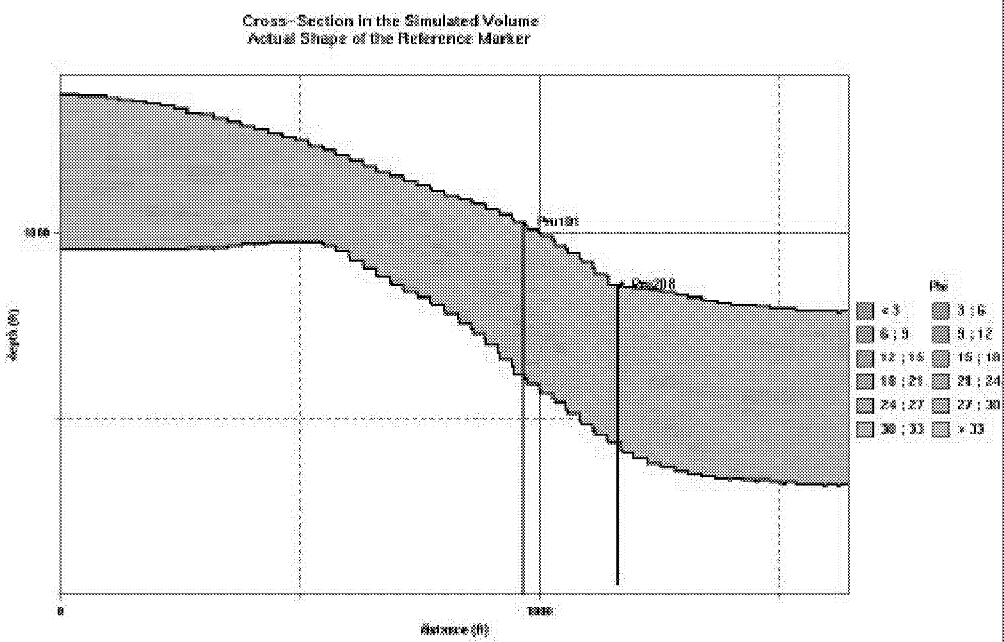


Figure 5-14: Porosity distributions in the top lithounit for the NW-SE cross section.

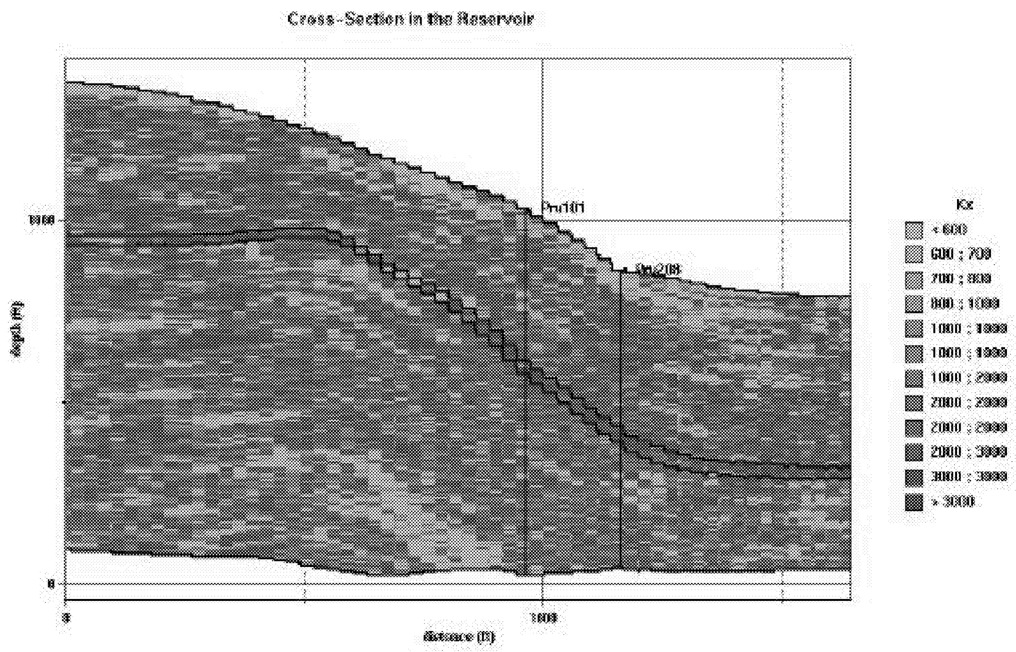


Figure 5-15: Permeability distribution in the NW-SE cross section of the entire reservoir (all lithounits).

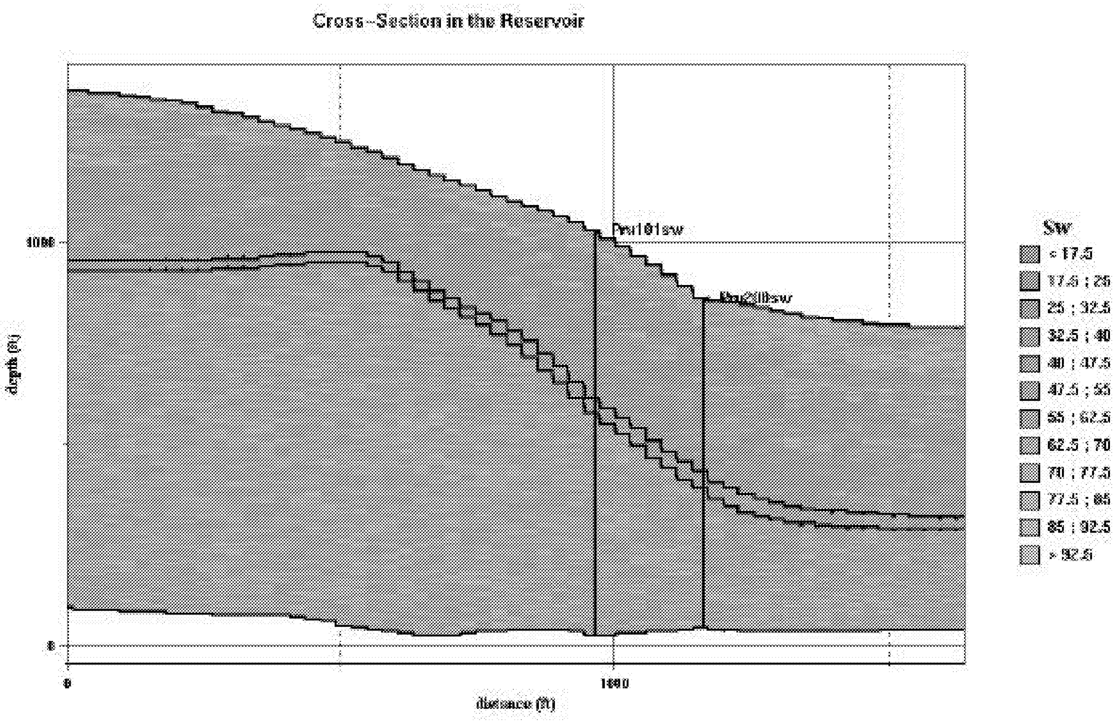


Figure 5-16: Water saturation distribution in the NW-SE section of the Monarch Sand reservoir.

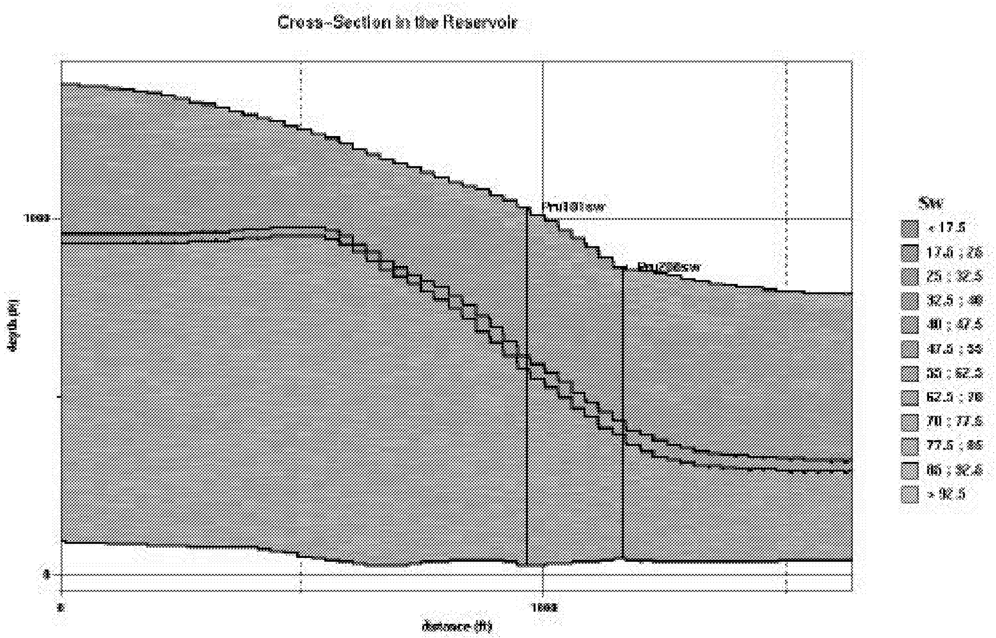


Figure 5-17: A second realization of water saturation in the NW-SE cross section.

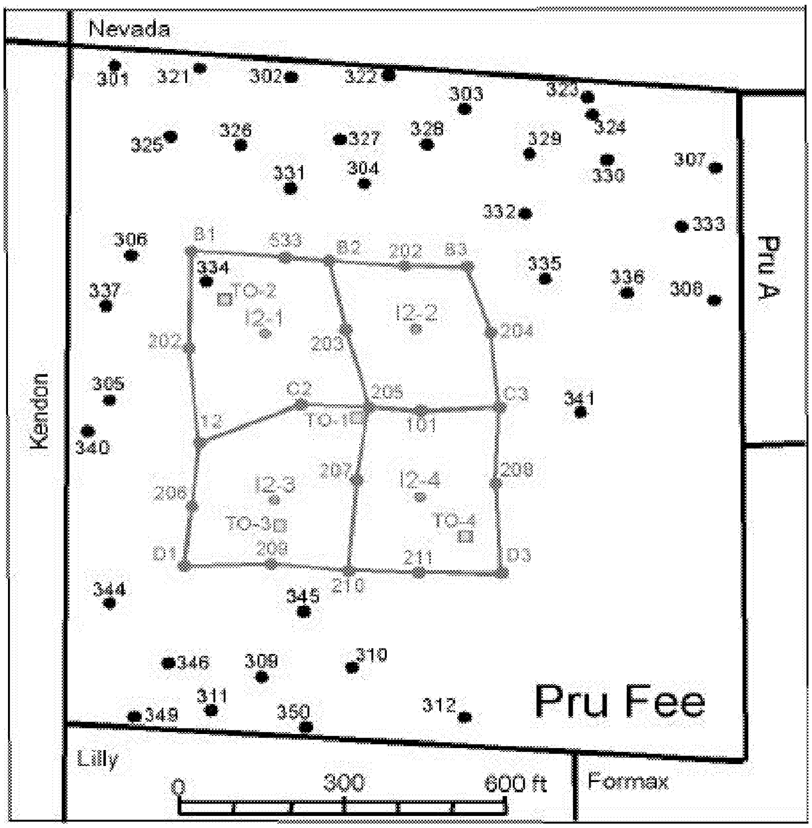


Figure 5-18: Map of the initial steam flood pilot consisting of four nine-spot patterns.

Figure 5-19: Up-scaled porosity model of Monarch Sand in NW-SE cross section.

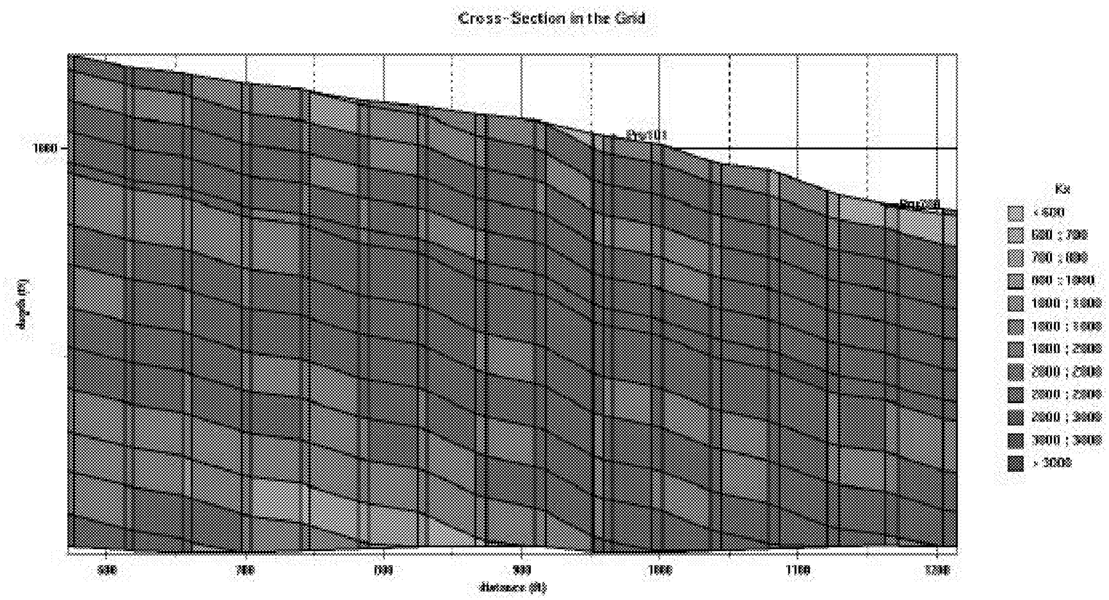


Figure 5-20: Upscaled permeability model of Monarch Sand in NW-SE cross section.

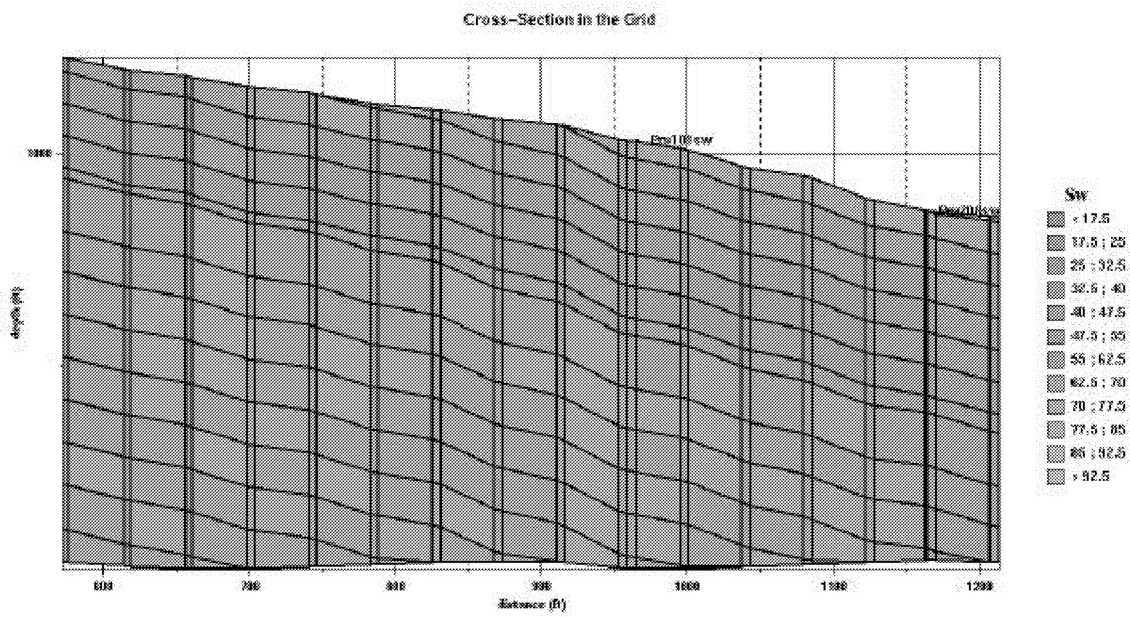


Figure 5-21: Up-scaled water saturation model of Monarch Sand in NW-SE cross section.

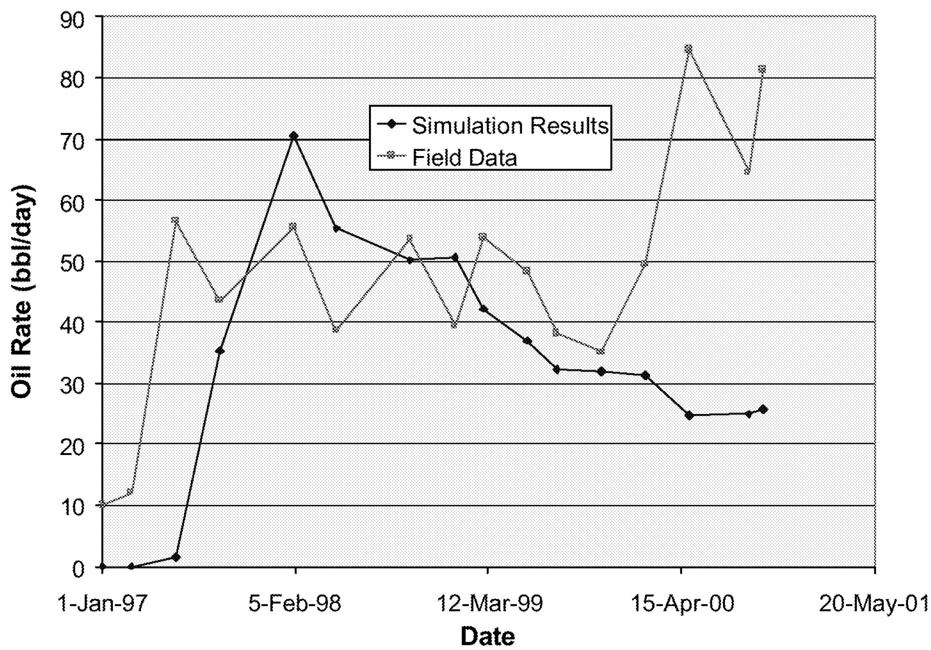


Figure 5-22: Comparison of oil rates predicted by simulations with the actual field oil rates.

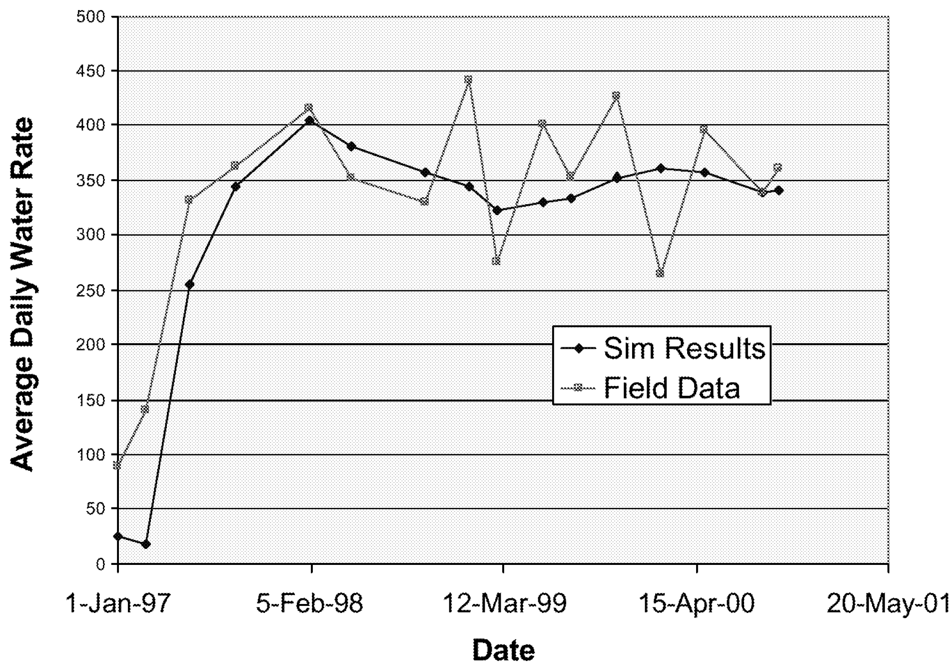


Figure 5-23: Comparison of the water rates predicted by simulation with the actual field water rates.

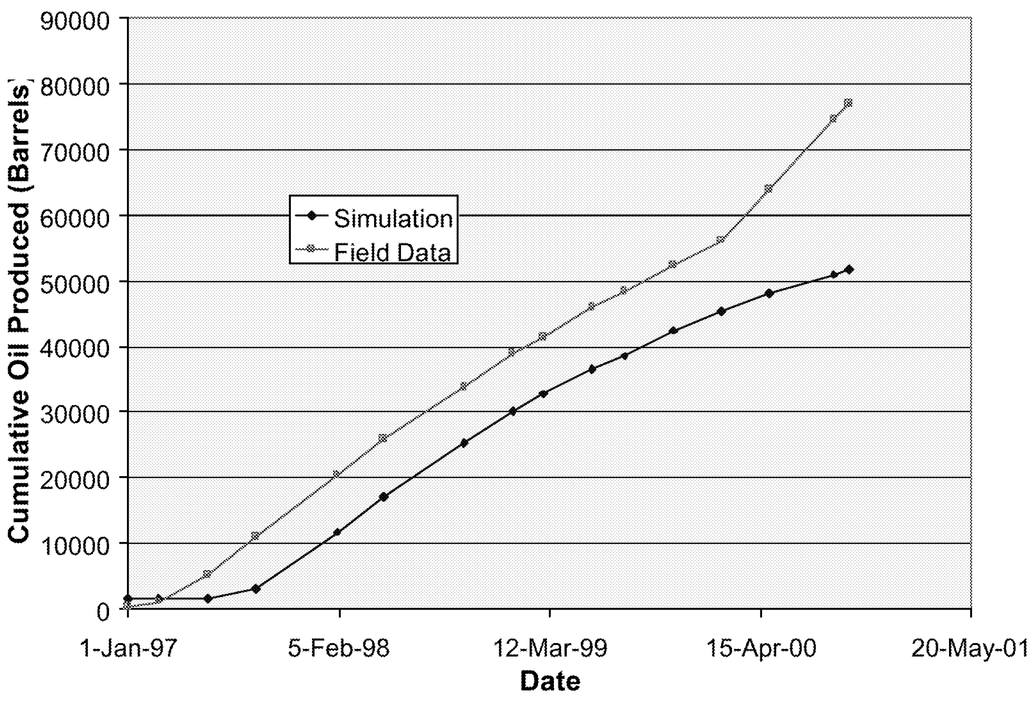


Figure 24: Comparison of the cumulative oil production predicted by simulations to the actual cumulative production from Pattern 2.

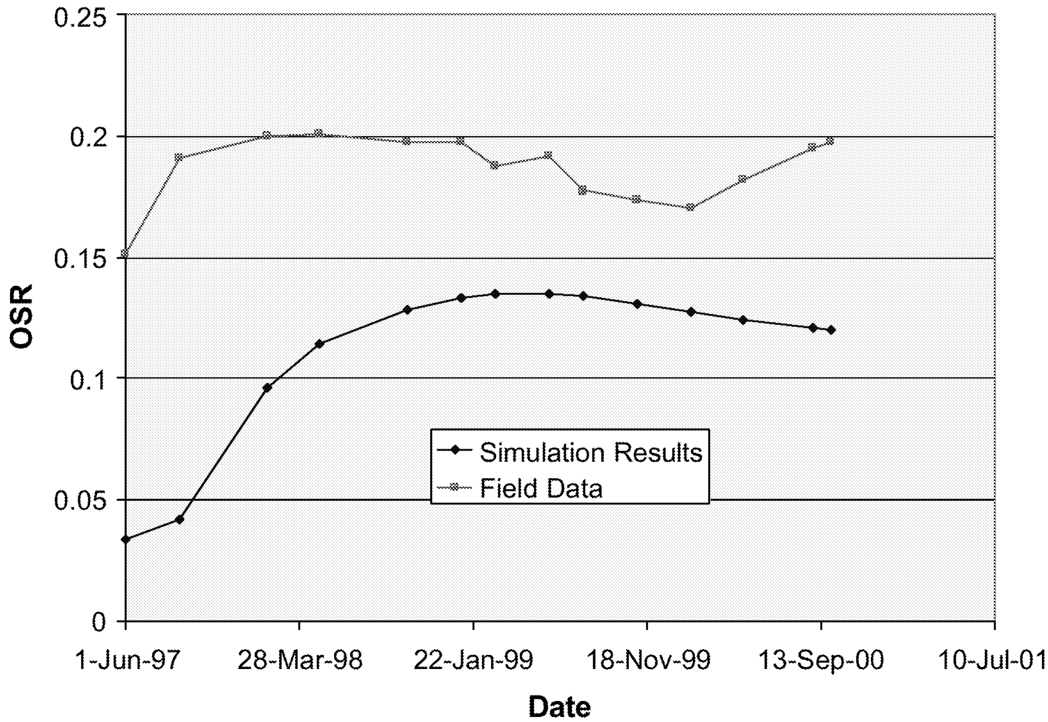


Figure 5-25: Comparison of the oil-steam ratios (OSR) predicted by the simulations to actual field data.

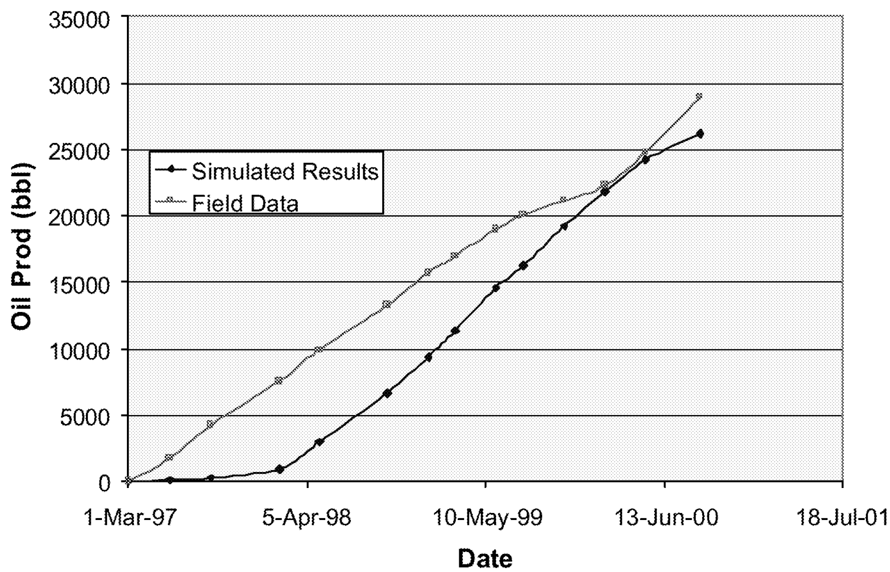


Figure 5-26: Cumulative oil production in a single well (????) in Pattern 2; a comparison of the simulation values to actual cummulative production for the well.

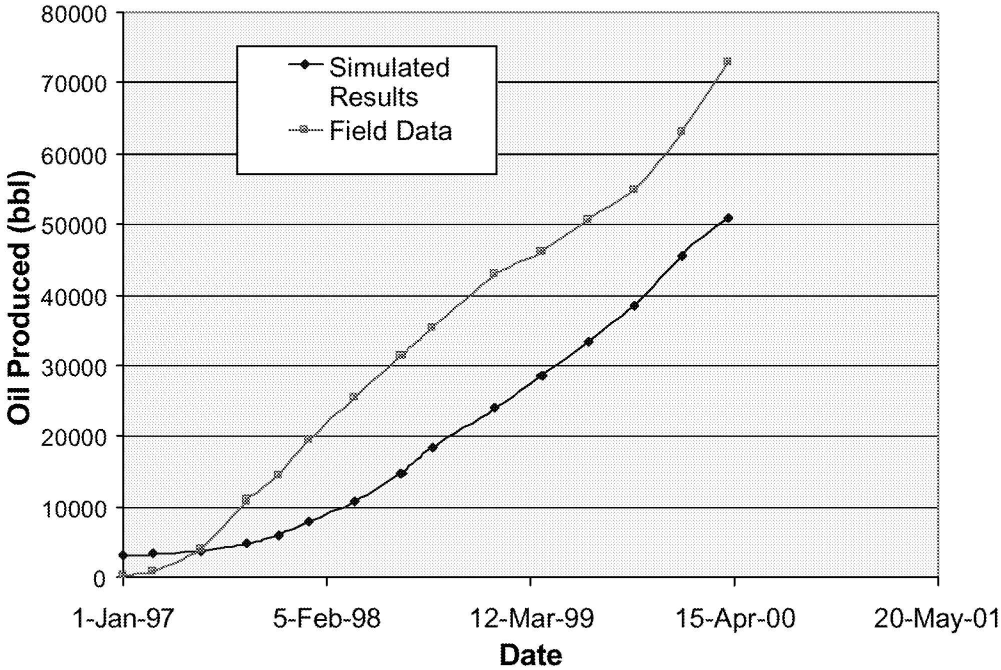


Figure 5-27: Comparison of the simulated cumulative oil production for Pattern 4 compared with actual field data for the pattern.

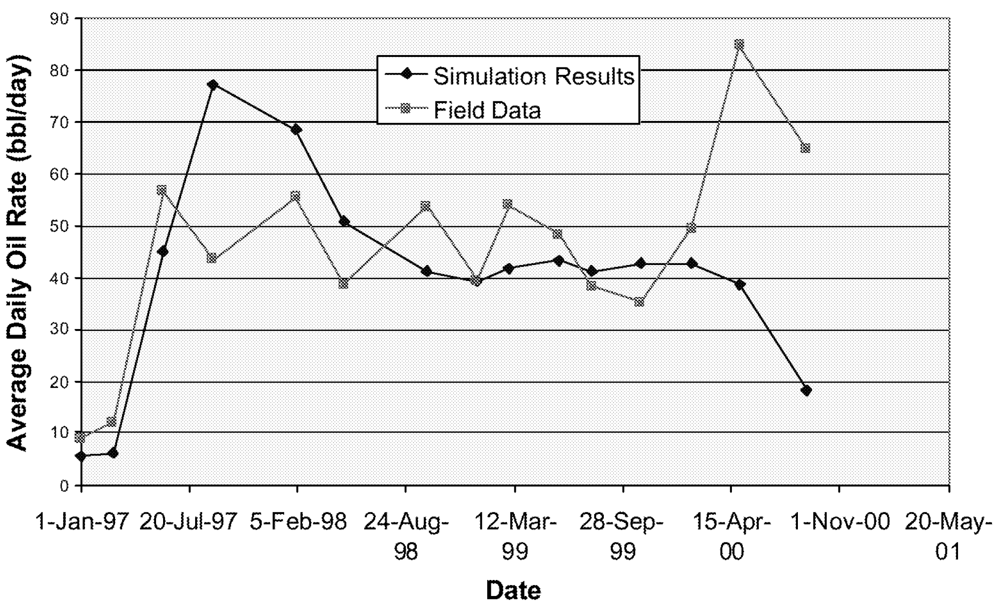


Figure 5-28: Simulated oil rate assuming an initial reservoir temperature of 150^{0}F compared with actual field oil rate.

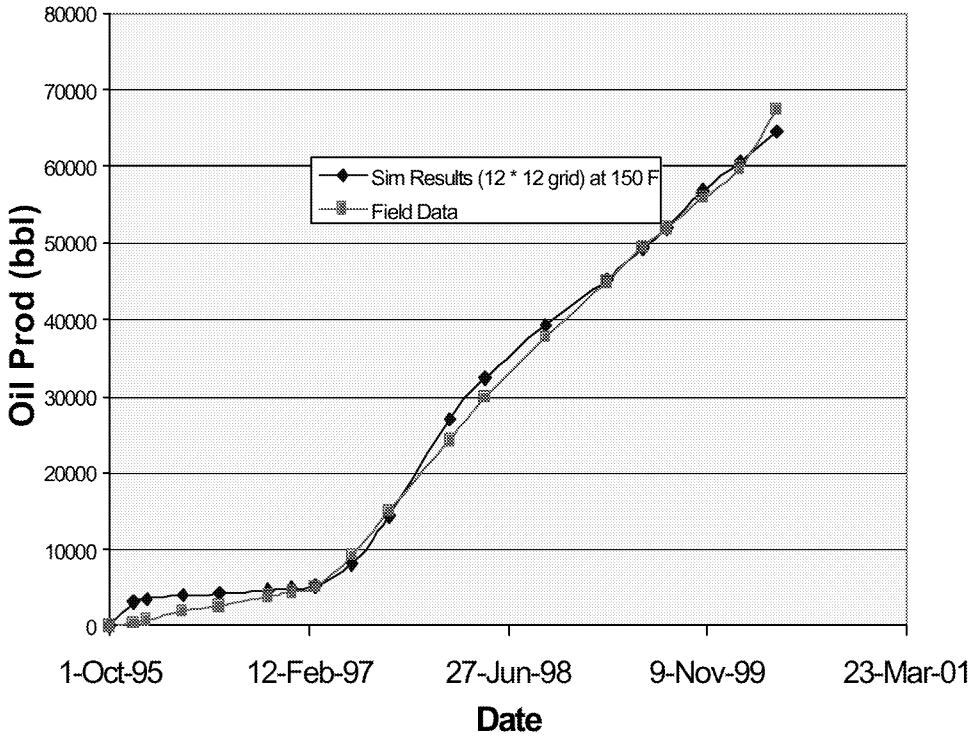


Figure 5-29: Simulated oil rate for Pattern 2 assuming an initial reservoir temperature of 150^{0}F compared with actual field oil rate.

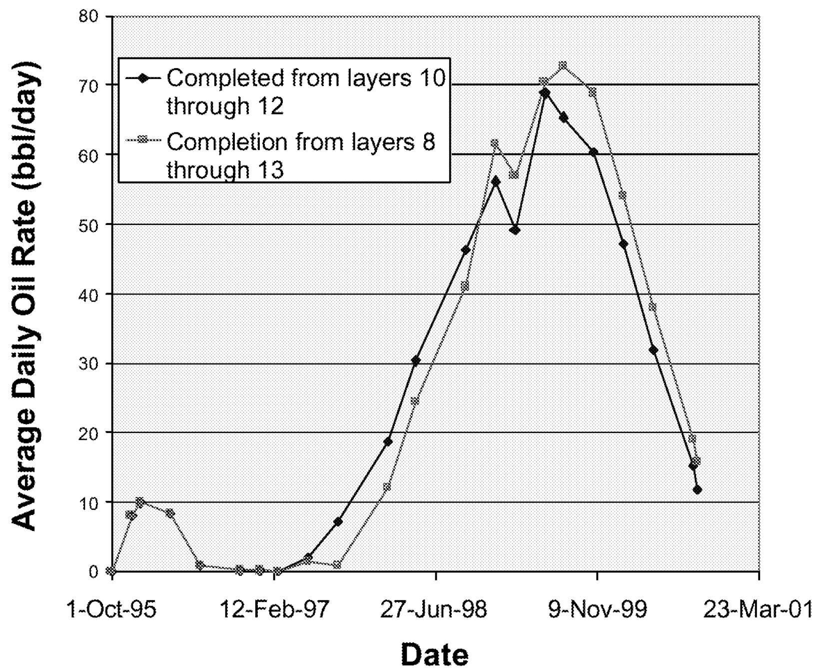


Figure 5-30: Simulated oil rate for two contrasting completion strategies.

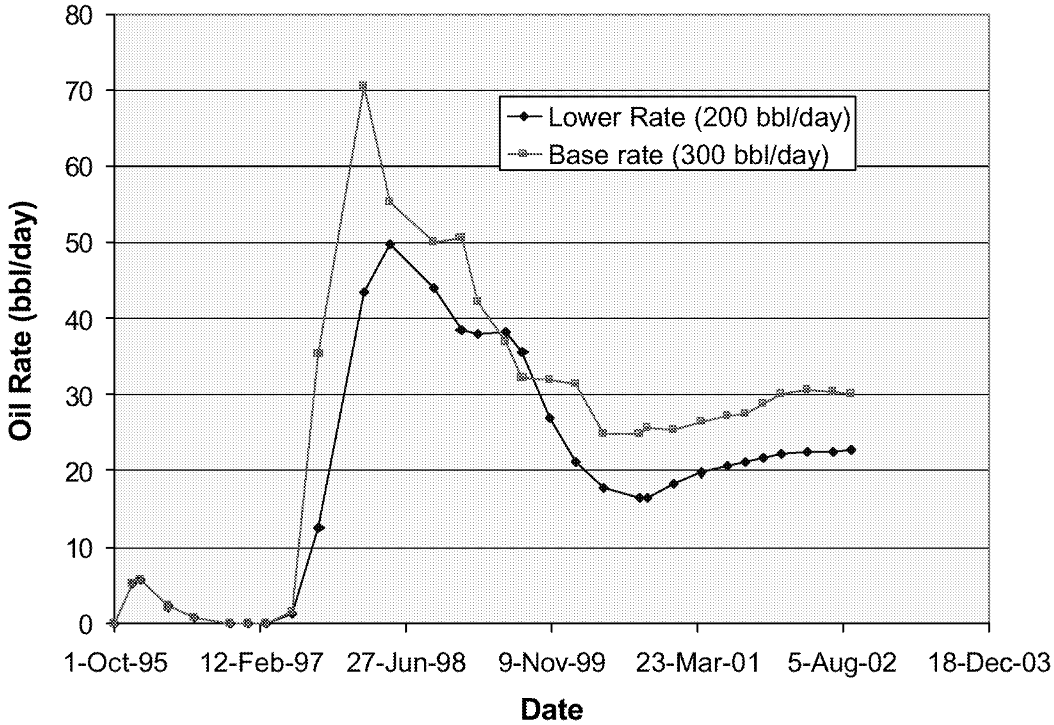


Figure 5-31: Simulated oil rate for different injection rates.

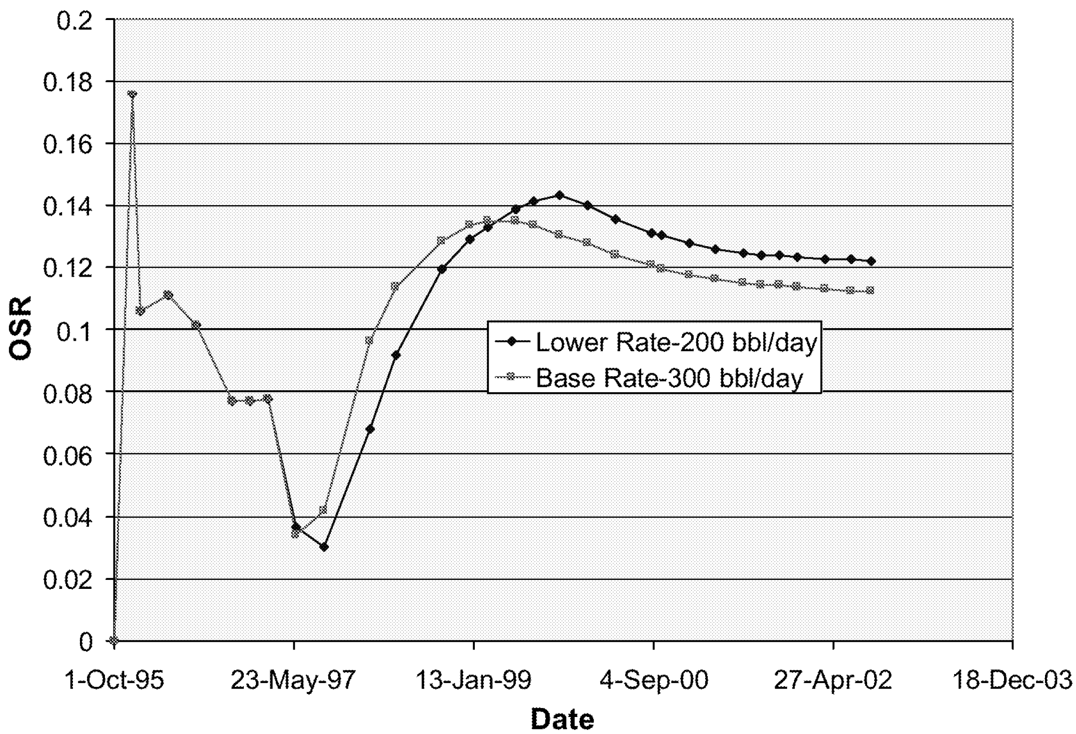


Figure 5-32: Simulated OSR for different steam injection rates.

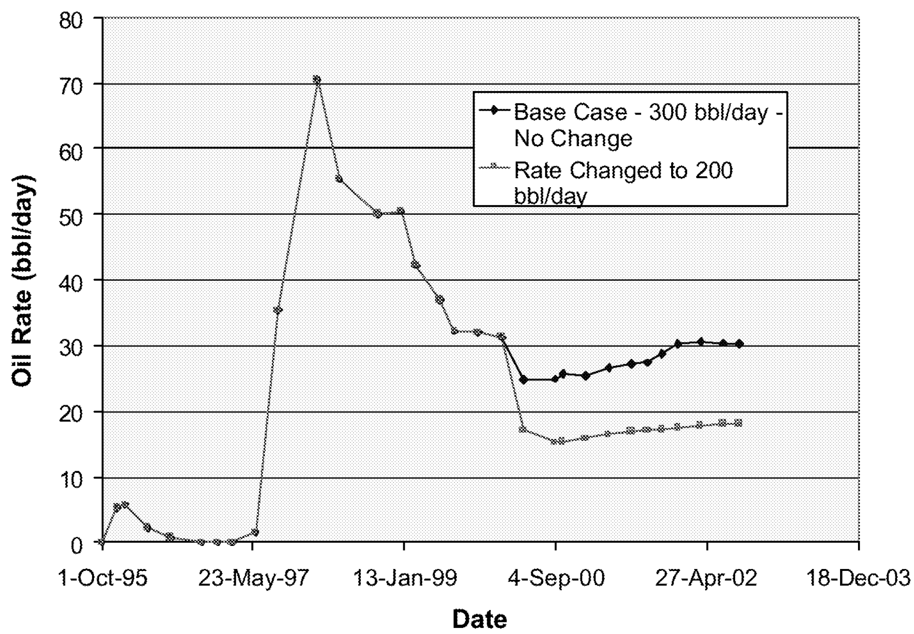


Figure 5-33: Variation in simulated oil rate when the injection rate is reduced from 300 bbl/day to 200 bbl/day on January 1, 2000.

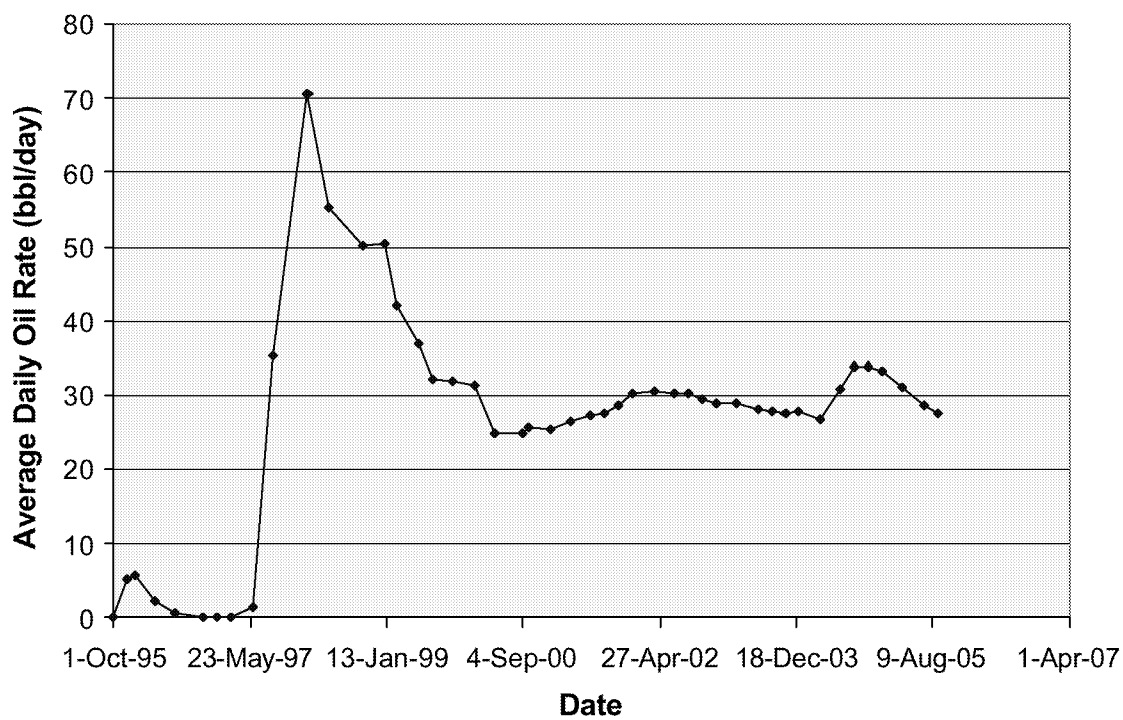


Figure 5-34: Predicted oil rate for Pru Fee pilot through October 2005.

Chapter 6

Summary of Technical Results

Introduction

It is highly likely that without the incentives to ARCO Western Energy (AWE) to partner with the DOE Class Program in carrying out this oil technology demonstration, the Pru Fee property never would have been brought back into production. Based on historic performance and the existing geologic evaluation, it was known to be a highly marginal property. Yet, in the four and a half years since the initiation of steam flood pilot the total production from this 40 acre shut-in tract has gone from zero to nearly 1,400 bopd (Fig. 6-1). In addition, the two operators, AWE and Aera Energy LLC, have invested, *without* a DOE matching contribution, in a total of 54 new producers external to the steam flood pilot, 10 new injectors increasing the number of steam flood patterns from 4 to 14, three additional temperature observation wells, and the steam generation/distribution infrastructure to support the expanded operations (Figs. 6-2 to 6-4). Total production from both the Monarch Sand and the Tulare reservoirs at the Pre Fee property from the end of 1995 through March 2001 is 1,066.1 MBO (Table 6-1). Through March 2001 1,066.1 MBO was produced from the Monarch Sand reservoir alone at rates approaching 1,200 bopd.

Table 6-1

Cumulative Production at Pru Fee Demonstration Site through March 2001

Pru Fee	Oil (bbls)	Steam-C	Steam-F	Water (bbls)	OSR	OWR
Pilot: cyclic	28,975	200,268		183,774	0.14	0.16
Pilot: flood	533,391	443,824	1,468,374	2,749,265	0.28	0.19
300-series: cyclic	201,648	795,882		935,941	0.25	0.22
300-series: flood	302,178	422,621	2,236,295	1,096,923	0.11	0.28
Tulare: cyclic	139,470	517,420		1,380,326	0.27	0.10
Totals =	**1,205,662**	**2,380,015**	**3,704,669**	**6,346,229**		

Viewed from the perspective of the history of oil production at the site over a period of eighty years (Fig. 6-4) the current oil rates are about eight times the maximum reached in the early years of primary production and four times greater than the maximum reached at the onset of initial thermal recovery in the early 1970's. Along with the increase in oil rate there has been a proportionally larger increase in water rate, which now stands near 180,000 bbls per month. It is still too early in the current production cycle at Pru Fee to know if the oil rates are increasing further, or have peaked and will begin to decline. All indications suggest that the oil rate is still building as the Monarch Sand is brought up to optimal temperature for steam flood recovery.

Renovation of the Shut-in Pru Fee Asset

The principal objective of the project was to test the effectiveness of steam flood as a enhanced thermal recovery method for production of heavy oils from a low-dip reservoir in the Midway-Sunset field. The premise behind the Class 3 oil technology demonstration was that the proper application of this EOR method could revive commercial production from a shut-in oil asset that the owner, ARCO Western Energy (AWE), had considered non-commercial upon careful and repeated evaluation. The aspects of the property that at first condemned it, while found to be essentially accurate descriptions of the reservoir, are clearly not an impediment to commercial production in steam flood. Indeed, as a year of successful production of the "300-series" wells in cyclic recovery mode has shown (Fig. 6-6), steam flood may merely enhance the economics of production. Even an older cyclic producer, such as Pru-13, once renovated can be very productive over a sustained period (Fig. 6-7).

Production rates (Fig. 6-6) after the entire property was put into steam flood shows the incremental benefits of this recovery mode. As the Pru Fee asset was transitioning from mixed flood and cyclic to full steam flood the steam rates per pilot pattern dropped from the target 280-300 bspd to about 200 bspd (Fig. 6-8). The steam was needed to maintain an aggressive injection rate in the new patterns. Yet the oil rates increased in the pilot patterns, as well as in the new patterns. Even the Pru-13 renovated well showed a pronounced increase in oil rate (Fig. 6-7) following the start of flood in pattern 10.

As expected, the mechanism at work in the low-dip Monarch Sand reservoir is convective drive, not gravity drainage. This mechanism is becoming more effective as more of the reservoir is heated and pressured up. The relatively sluggish performance of the pilot in the second and third years of operation may be due to the relatively low initial steam flux (<300 bspd per well) utilized. It was this assessment that lead Aera Energy LLC to use high injection rates in the new patterns in order to heat the reservoir quickly and start convective drive. The effects appear to be greater in the already hot pilot patterns, than the still warming new patterns.

Following the initial characterization of the reservoir in 1996, it was thought that there were insufficient steam baffles or barriers within the Monarch Sand reservoir to hold the steam where injected. Early indications suggested that the steam was rising upward from the injectors over short distances and by-passing significant parts of the reservoir volume. However, with time it has become clear that the steam generally is staying at or very near the level injected. The zones of heating are broadening downward through time, not upward. There are, indeed, stratigraphic controls on the migration of steam, and well documented examples of early fingering of the steam along stratigraphic zones. The most effective baffle, perhaps locally a true barrier, is the "middle marker" horizon. In the two northern patterns of the pilot steam is diverted both above and below this thin diatomite mudstone lens. In the southern two patterns, steam is confined above the unit. This knowledge will prove useful in future management of steam flood at the property.

In as much as the operation on the Pru Fee property are intimately tied to other adjacent Aera Energy LLC production activities, the company is understandably reluctant to disclose details of the economics of the steam flood project. However, the economics were characterized in a public workshop as "better than anticipated", being a "technical and commercial success" with a rate of return greater than 25%.

Another approach to the economics might be to revisit the projections made for the pilot during the initial feasibility study in 1995-1996. The integrated reservoir characterization and production simulation study predicted gross expected reserves at a realistic economic limit for an 8-ac four-pattern pilot alone of 550 MBO. This recoverable reserve estimate was derived from the oil rates simulated for a four-pattern array in the center of the Pru Fee property using a 9-spot, no cycles steam flood base case. This base case used a constant steam rate of 300 bspd per injector (1200 bspd for the entire pilot) over the life of the project. The simulation predicted an initial 10 bopd for new wells, ramping up to 29 bopd (320 bopd for entire pilot) in 16 months. The production would remain relatively flat for 28 months, then start declining harmonically at 40% towards the economic limit. The pilot would reach its economic limit at the end of 2003 after producing 550.5 MBO. By the end of December 2000 the pilot had already produced 409.4 MBO, which is 27% more than predicted. The pilot would already be in decline by that date, something that appears not to be happening.

These production projections were used to model the economics of the 8-acre pilot. With a projected $1,900,000 gross capital investment for installing the four-pattern pilot, the project had an estimated after-tax profit (PW10) of $1,177,000 and rate of return of 49% based on non-inflated economics. The projected production cost per barrel of oil would be $2.89. Target additional recoverable reserves in the other 32 acres of the property were estimated to be 2.75 MMBO or greater. The economic model figured an oil price of $14.25, which with the broad swings of the period 1997-2000 might be a bit low, and a gas price of $2.13. The actual gas price over the four-year period averaged $3.29. The higher oil production clearly compensates for the higher gas price.

A goal of the project was to encourage other California producers to attempt to revive shut-in oil properties. To that end, Aera Energy LLC is now actively developing the Lilly property immediately south of Pru Fee. This was one of the 29 properties in the Midway-Sunset field that were shut-in at the start of this DOE-sponsored project. During the first half of 2001 exceptionally high gas prices in California have forced many thermal recovery projects in the southern San Joaquin Basin to be shut-in, even in a period of near record high oil price. However, through this period of high operating costs Pru Fee, a property once shut-in as economically marginal, continued to operate.

Well Completion Strategy

The four injector wells in the Pru Fee pilot all were completed with large standoffs from the OWC in order to be assured that steam was injected into the portion of the Monarch Sand reservoir with highest oil saturation. The heat capacity of water is more than twice that of oil (Burger et al., 1986). In injecting steam into parts of the reservoir with high water saturations the heat is taken up disproportionally in heating formation water, thus lowering the economic efficiency of the steam flood operation. Although total recovery from the reservoir might be increased, the additional oil comes at the expense of lower performance factors, OSR and OWR.

Although we had wished to test this concept by making changes to the injector string in different Pru Fee pilot injectors, the opportunity never presented itself at the project site. However, a test of the concept was performed nearby in the course of renovation of a group of 17 poorly performing steam flood patterns. The injectors in these patterns initially had been perforated through the entire Monarch Sand pay zone.

In the summer of 1999, Aera Energy LLC, observing the manner in which the injectors in the four-pattern Pru Fee pilot were completed, adopted the concept of a large stand-off from the OWC in injector workovers in the "low dip" portion of the Kendon lease immediately west of Pru Fee (Fig. 1-5). The new perforations were placed in the uppermost one-third to one-half of the Monarch Sand, well above the OWC and the Sw transition zone, and deeper existing perforations sealed. The response from the injector workover using the recommended standoff from the OWC has been outstanding (Fig. 6-9). Increases in oil rates in the renovated patterns average 25 bopd per well with a total increase being over 900 bopd. The OSR increased from 0.20 to 0.35 and the water cut improved.

When AWE decided to put an additional 37 cyclic producers on the Pru Fee property surrounding the steam flood pilot, it seemed like an ideal opportunity to compare thermal recovery methods in the same well characterized reservoir. However, the "300-series" wells were completed open-hole, without the gravel pack that was placed in the pilot producers. The differences in performance are striking (Figs. 6-10 and 6-11), even given the large spatial variability in the performance of each producer. In part the lower per well rates for the "300-series" wells relate to there location in parts of the reservoir with lower than average oil saturations (compare Fig. 6-12) to Fig. 3-40). Part of the variability relates to reservoir temperature as evidenced by the flow line temperature of each well (Fig. 6-13). The "open-hole" wells have an average rate of about 20 bopd versus the gravel-packed pilot producers with a per-well average oil rate of about 30 bopd (Fig. 6-10). Gravel pack completions are clearly a good investment.

Technology Transfer

In order to keep the petroleum industry well informed about the progress and technical success of this project members of the project team have pursued a program of proactive technology transfer. This has included issuing updates on the project in publications likely to be read by thermal recovery operators. Also there have been numerous presentations, many invited, at research conferences, technical meetings and professional conventions. These gatherings have been sponsored by the Petroleum Technology Transfer Council (PTTC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE). We even accepted an invitation to describe the project at an AAPG-AMGP international research conference on mature field development in Veracruz, Mexico. Normally there were several such professional presentations each year of the project. In addition, the team has responded to requests by individual operators for reports and in-house presentations. The specific technology transfer activities in each year are described in the annual project reports.

There have been two public workshops held in Bakersfield, California to present to a broad group of operators and service providers the major findings of the project. The first was held in early December 1996 at the close of the feasibility study. The second was held in late February 2001 to describe the success of steam flood in renewing production for the shut-in Pru Fee property.

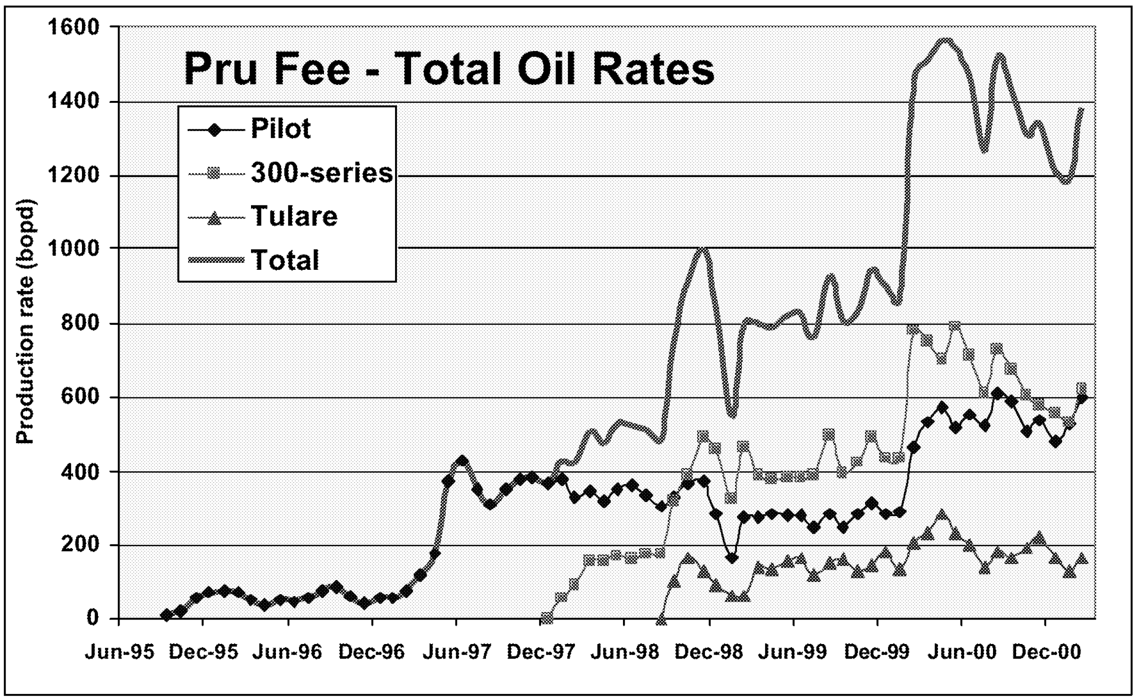


Figure 6-1: Oil rates (bopd) for the Pru Fee property over the entire period of the DOE project. After the start of steam flood on the entire property production increased dramatically to about 1,400 bopd. The plot includes shallow Tulare Formation oil.

Figure 6-2: View north eastward across the entire 40 acre Pru Fee property. The Pru-209 producer is in the foreground. The white steam generators are near the center of the property.

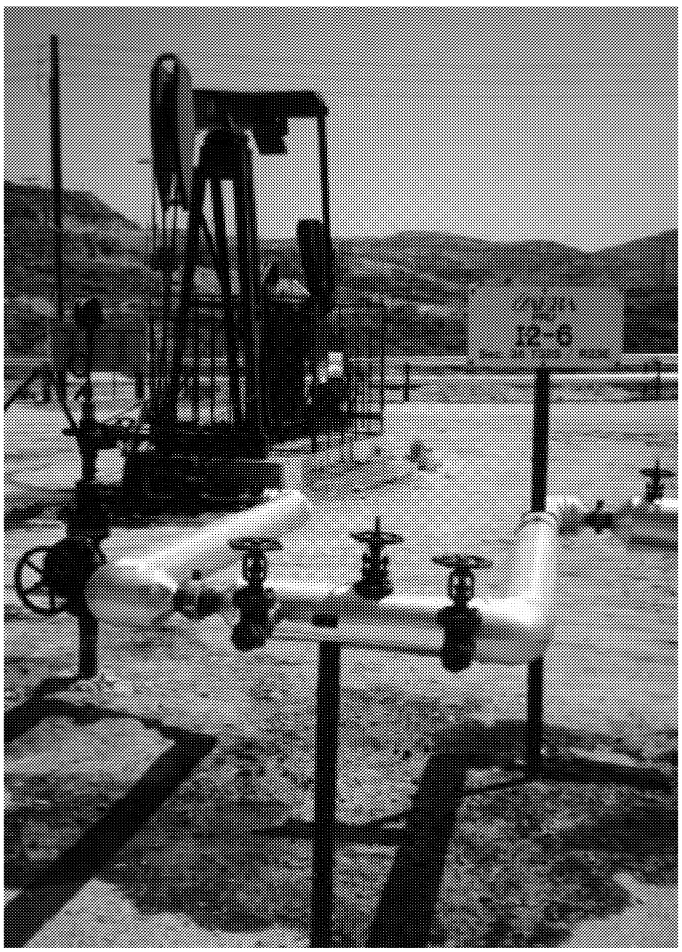


Figure 6-3: The Aera Energy LLC Pru I2-6 injector and Pru 345 producer.

Figure 6-4: Auto well tester #1 unit for metering Pru Fee producers on-site. The unit was installed by Aera Energy in preparation for beginning steam flood of "300-series wells in early 2000.

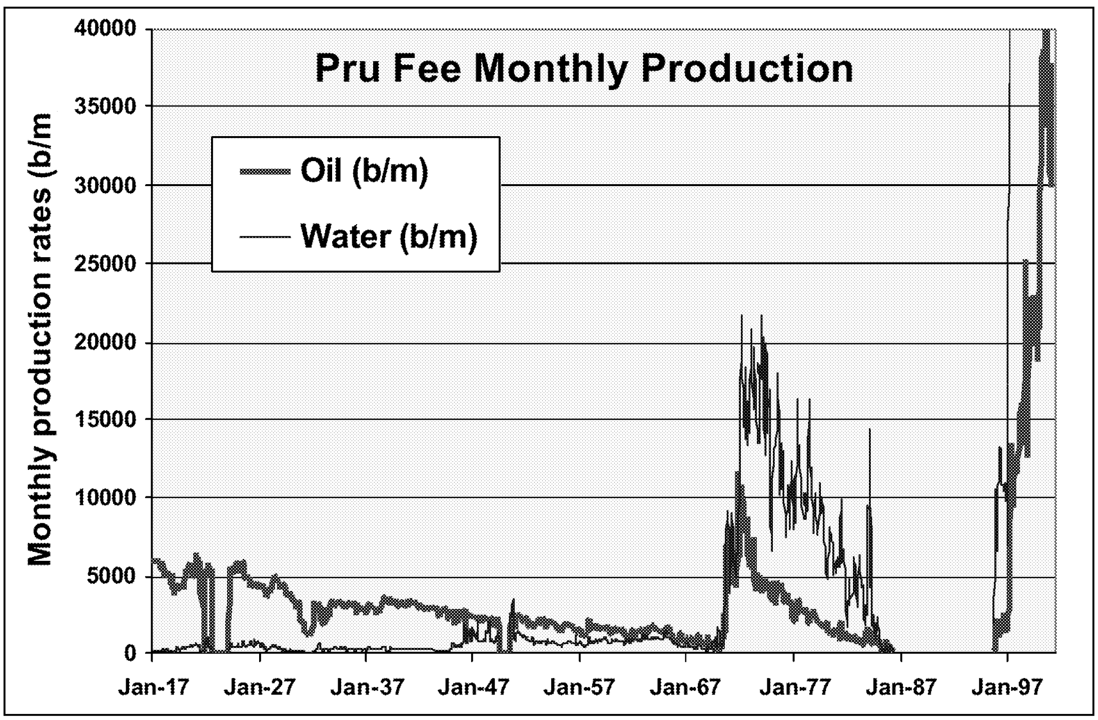


Figure 6-5: Monthly oil rates over the entire operational history of the Pru Fee property.

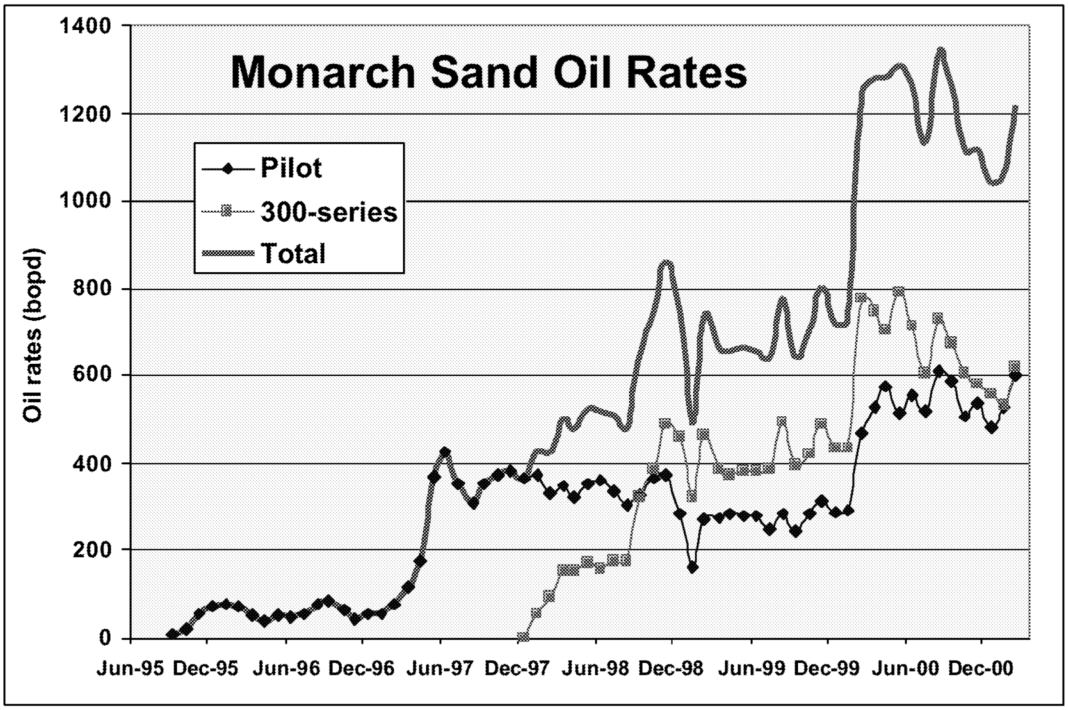


Figure 6-6: Oil rates for the Monarch Sand reservoir at Pru Fee.

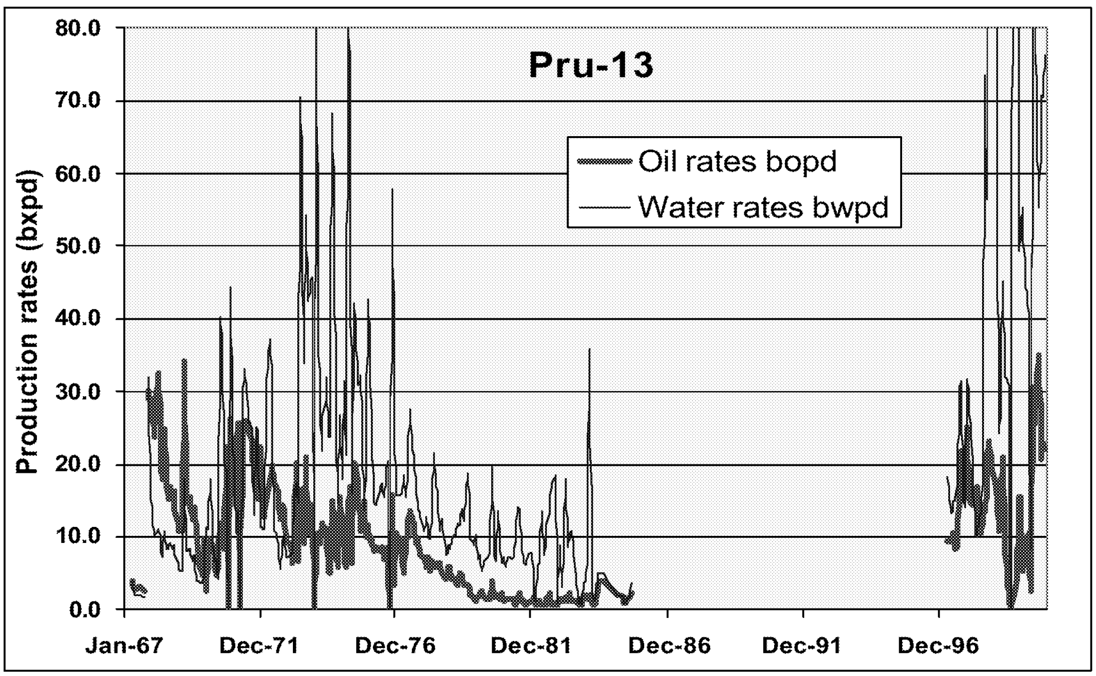


Figure 6-7: Oil and water production rates for the renovated Pru-13 producer. Production came on strong to about 20 bopd when first put into cyclic steam in early 1997, but fell off quickly to less than 10 bopd. Once steam flood began in the pattern (#10) occupied by this well the oil rate increased to about 30 bopd.

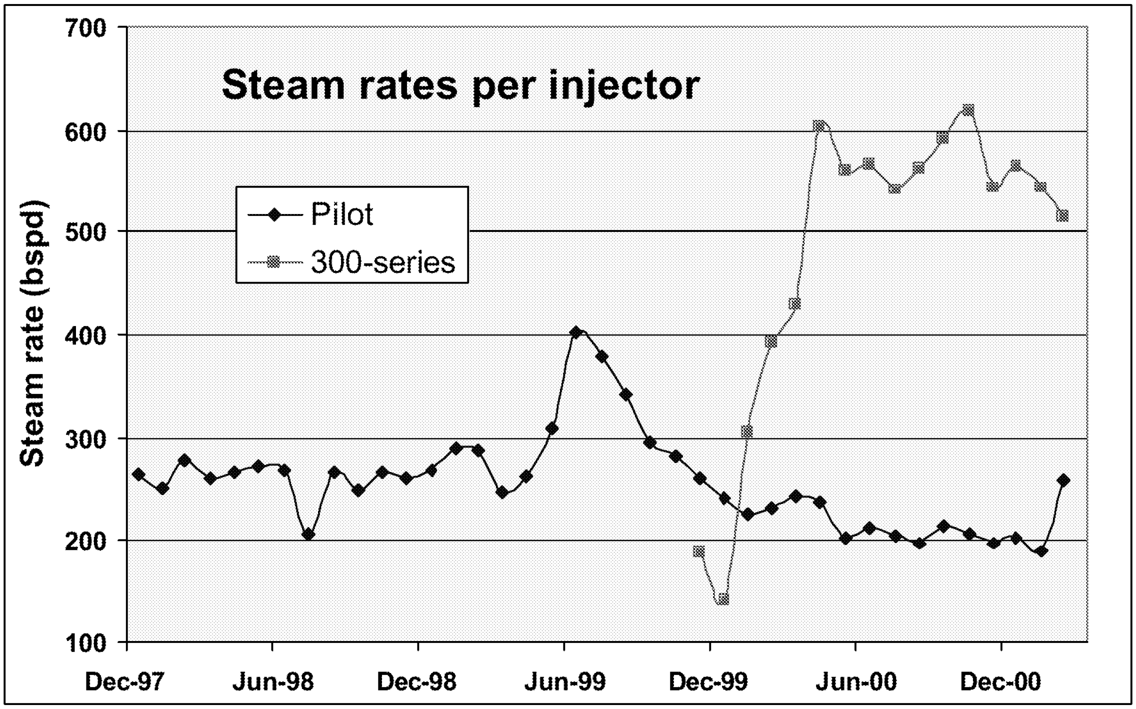


Figure 6-8: As the Pru Fee asset was transitioning from mixed flood and cyclic to full steam flood the steam rates per pilot pattern dropped from the target 280-300 bspd to about 200 bspd. The steam was needed to maintain an aggressive injection rate in the new patterns. Yet the oil rates increased in the pilot patterns (Fig. 6-6).

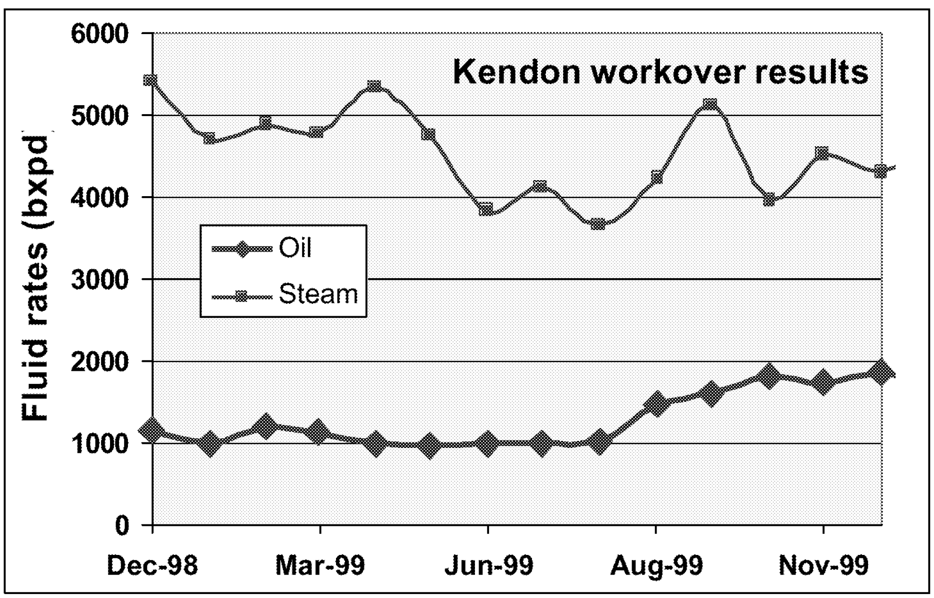


Figure 6-9: Production increase associated with workover of steam injectors in 17 "low-dip" Kendon steam flood patterns to raise the injection points creating a large standoff from the OWC. The workover showed the value of placing the steam in the high So parts of the reservoir.

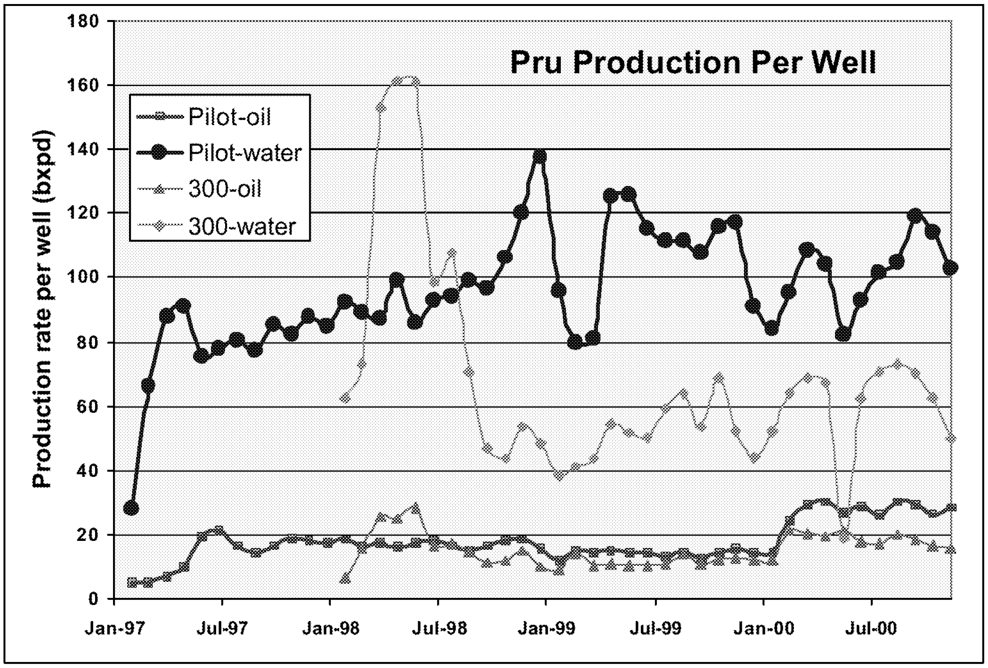


Figure 6-10: Average per-well oil and water rates comparing performance of the pilot to that of the "300-series" wells. The oil rates are similar until the onset of steam flood across the entire property, at which point the pilot rates rise to about 30 bopd per producer.

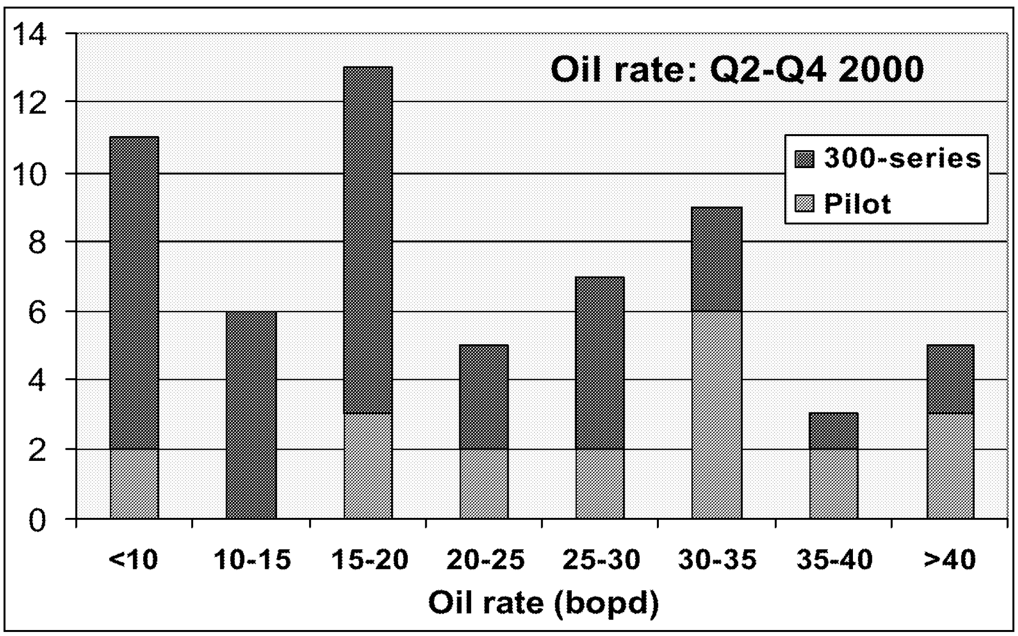


Figure 6-11: Stacked histogram of per-well oil rate averaged for the first three quarters of 2000. Note both the over lap of rates, as well as the concentration of lower rates in the "300-series" wells. The latter group of wells have "open-hole" completions.

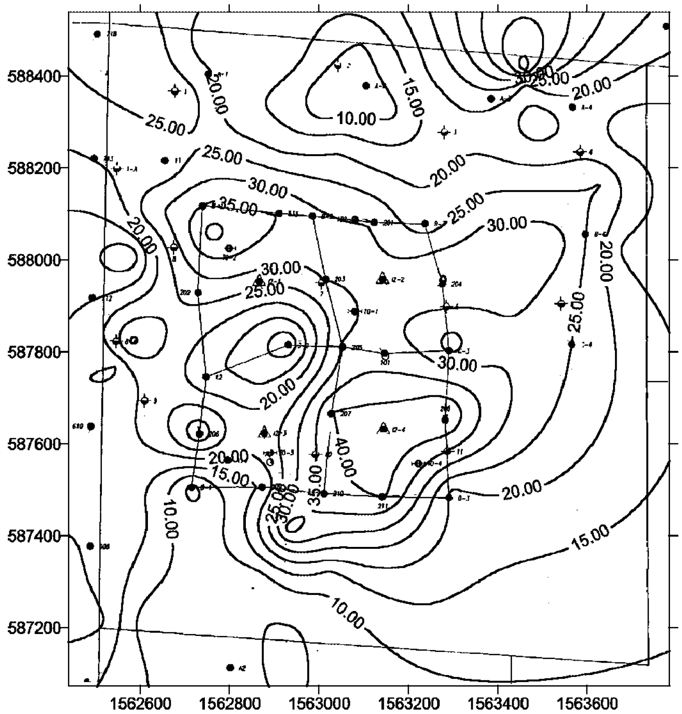


Figure 6-12: Contour map of the per well oil rates averaged over the first three quarters of 2000. The higher rates in general are associated with the pilot patterns, except for the production hole centered on the poorly performing Pru-B1 well. Lower rates are associated with the oil depleted areas in the north and northwest of the property.

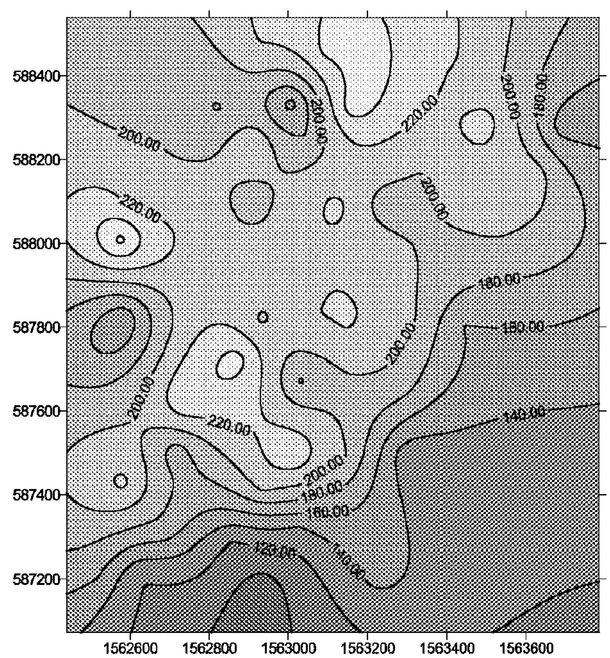


Figure 6-13: Contoured flow line temperatures (°F) for individual producers averaged for the first three quarters of 2000. The highest temperatures are associated with the pilot, which has been in steam flood since early 1997, but oil rates are high, and the two oil depleted regions in the north and northwest, where oil rates are very low.

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